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Cover Image: Plant operators take a safety walk at BASF's 90,000-tpy acetylene plant at its Ludwigshafen Verbund site in Germany. Photo courtesy of BASF.

HP Industry Perspectives

A sincere thank you for a successful IRPC

In late September, *Hydrocarbon Processing* hosted the International Refining and Petrochemical Conference (IRPC) in Houston, Texas (U.S.)—the first in-person IRPC in nearly 3 yr. For more than 14 yr, the IRPC technical event has gathered key players in the global refining and petrochemicals sector to share knowledge, best practices and the latest technologies, services and equipment that are revolutionizing the processing industries. This year's IRPC highlighted dozens of new and updated technologies, services and equipment that are leading the hydrocarbon processing industry (HPI) towards a safer, more efficient, more profitable and sustainable work environment.

The two-day event was highlighted by timely keynote presentations on decarbonization, the current state of the HPI and a look at the refinery of the future. These presentations were conducted by:

- Isa Mbaraka, Sustainability Director, Olefins and Aromatics Technology Center, Dow Chemical
- Patricia Scozzafave, Decarbonization Consultancy Services Manager, Shell
- Poornima Sharma, Vice President, Operations, Americas and Europe, Technip Energies
- Stan Carp, Senior Manager-Integrated Project Solutions, Honeywell UOP
- Matt Kimmel, Senior Research Analyst-Refining and Oil Markets, Wood Mackenzie.

The bulk of IRPC's agenda featured presentations from HPI professionals around the world on the following topics: plant design, engineering and construction; process optimization, emerging technologies, process controls, instrumentation and automation; digital transformation; the circular economy; biofuels and alternative/renewable fuels; FCC/hydrocracking; alkylation; maintenance and reliability; and gas treatment/processing, among others.

Hydrocarbon Processing extends a heartfelt thank you to all presenters for their time and effort in sharing their knowledge and experience. The technologies, best practices, maintenance know-how and operational efficiencies were on full display to inform and present a call-to-action for a safer, more profitable and more efficient working environment. The knowledge presented through case studies, videos and anecdotes displayed how the industry's technologies and workflows are operated in real-world scenarios. What better way to learn than through real-world experiences?

Hydrocarbon Processing would also like to thank the sponsors of the event: Alleima, Aspentech, Atlas Copco, Honeywell UOP and Linde, as well as the numerous exhibitors. And, as always, we want to thank our hydrocarbon processing community for their continued support.

The ability to share knowledge and best practices from colleagues around the world is a testament to the desire of industry personnel to pursue operational excellence. HP

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Hydrocarbon Processing recognizes the latest innovations at its sixth-annual *HP* Awards

On October 12, *Hydrocarbon Processing* hosted its annual *HP* Awards at the Houstonian Hotel, Club and Spa in Houston, Texas. This event recognizes the latest innovations, technologies and services in the global hydrocarbon processing industry (HPI), as well as the people that have and are shaping the future of the HPI. The benefits that these technologies and people bring to the industry have helped companies operate more safely, efficiently and profitably.

The 2022 *HP* Awards were comprised of 17 strategic categories (14 technical/services and three people-focused awards). *Hydrocarbon Processing* received more than 100 nominations from more than 20 countries around the world. Each abstract was voted on by an independent *Hydrocarbon Processing* advisory board, consisting primarily of owner-operators, engineering and technical licensing companies. TABLE 1 details the winners in each category.

Regardless of whether a technology, service or person was deemed a winner, these innovations and people should be recognized and celebrated for their contributions to the global processing industries. *Hydrocarbon Processing* would like to congratulate the winners and honor those that were finalists within their respective categories. HP

TABLE 1. *HP* Award winners by category

Category	Winner	Technology/Service
Best AR/VR/AI Technology	Symphony Industrial AI	Forecast 360™
Best Asset Monitoring Technology	Emerson	AMS Asset Monitor with AMS Machine Works Software v1.7
Best Asset Reliability/ Optimization Technology	Beyond Limits	LUMINAI Refinery Advisor
Best Automation Technology	Honeywell	Plant-Wide Optimizer
Best Catalyst Technology	Reliance Industries Ltd.	Olefins Removal Catalytic Technology (REL-ORCAT)
Best Digitalization Technology	Axens	Connect'In
Best Gas Processing/LNG Technology	Modular Plant Solutions	MeOH-To-Go®
Best Health, Safety or Environmental Contribution	Honeywell	Safety Watch Real-Time Locating System
Best Instrument Technology	Endress+Hauser	Proline 10 flowmeter line
Best Modeling Technology	Topnir	Topnir™ Crude Modeling
Best Petrochemical Technology	Axens	Atol®
Best Refining Technology	Technip Energies-Clariant Catalysts	EARTH® (Enhanced Annular Reforming Tube for Hydrogen and Syngas
Sustainability	Entropy Inc.	Modular Carbon Capture & Storage (MCCS™)
Licensor of the Year	Lummus Technology	–
Most Promising Engineer	Bharat Petroleum Corp. Ltd.	Aniruddha Kulkarni
Executive of the Year	Bharat Petroleum Corp. Ltd.	Dr. Rajeev Kumar
Lifetime Achievement	Topnir	Didier Lambert

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37 Design, Engineering and Construction.
Many challenges exist in the global capital projects sector, including supply chain disruptions, tight schedules, and economic and regulatory uncertainties. This articles provides several solutions to help capital project developers complete projects on time and on budget in a volatile, uncertain, complex and ambiguous world.

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Steam turbines are essential for successful operations in refining and petrochemical plants. This article focuses on optimizing steam-driven turbines to increase efficiency and reduce reliability issues.

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Equipment malfunction or an unplanned shutdown of a sulfur recovery unit can have a significant effect on a facility's profitability, as well as on personnel safety and the environment.

HYDROCARBON PROCESSING®

Enhancing how we deliver technical knowledge: The evolution of *Hydrocarbon Processing*

For more than 100 years, *Hydrocarbon Processing* has provided the global hydrocarbon processing industry with the latest advancements in processing technologies, maintenance, safety and know-how to improve and enhance refining and petrochemical plant operations. The publication, written for the industry by the industry, has been instrumental in disseminating ideas around the globe that have ultimately made the processing industries safer and more efficient, sustainable and profitable.

Over the past couple of years, *Hydrocarbon Processing* has prepared the ground for, and invested in, our digital offerings and how we deliver our content. Through considerable industry research and audience feedback, we are experiencing a clear demand for a more digitally oriented product.

In addition, our advertising and sponsorship partners expect *Hydrocarbon Processing* to lead by example and deliver a superior return on investment (ROI). With all that in mind, I am excited to announce that starting with our January 2023 issue, we will deliver all content through digital platforms.

This natural evolution of the way we deliver information, industry trends and technology advancements to our global readership will provide our readers an enhanced pathway to the latest topics industry professionals are seeking.

Hydrocarbon Processing readers and subscribers will continue to receive:

- Technical content and case histories (published online in real time and in a monthly, digital issue)
- Breaking news alerts and technological advances published online
- More than 25 high-quality e-newsletters per month
- Access to industry-leading thought leadership presentations
- The ability to attend downstream technical events and award programs hosted by *Hydrocarbon Processing.*

Advertisers and sponsors will continue to receive the following from *Hydrocarbon Processing*, with superior ROI:

- Access to decision-makers at global operating companies
- Branding through targeted advertising capabilities through *Hydrocarbon Processing*
- Unique and exclusive e-newsletter sponsorships
- Sponsored content and promotion through Downstream365 and The Main Column podcast
- The ability to generate quality leads through webcasts, whitepapers and e-books.

As the hydrocarbon industry continues to evolve, so will the way we deliver the latest advancements in plant operations and the technologies that propel this industry forward. We are excited to embark on this new chapter for *Hydrocarbon Processing.* We are also thrilled about what the future holds and are here to assist you in any way.

Kind regards,

LEE NICHOLS

Vice President, Content
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Gulf Energy

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HP Construction

AFRICA

Anchorage Investments has shortlisted four companies to build its $2-B Anchor Benitoite petrochemical complex project in Ain Sokhna, Egypt. These companies include **Hyundai, Samsung, Technip Energies** and **Tecnicas Reunidas.** Once completed, the Anchor Benitoite complex will produce 1.75 MMtpy of petrochemical products.

ASIA-PACIFIC

BASF has begun operation on several plants at its Verbund site in China. The $10-B facility is being built in Zhanjiang and represents BASF's largest single investment in the country. Once operational by 2030, the plant will produce up to 1 MMtpy of ethylene and other various petrochemicals.

In September, **Indian Oil Corp. (IOC)** awarded an engineering, procurement, construction and commissioning (EPCC) contract to Larsen & Toubro for the project's 2.5-MMtpy residue hydrocracking unit. This project is part of IOC's $4-B, 10-MMtpy expansion of the Panipet refinery and chemical complex in Haryana, India. Once completed, the complex's total capacity will reach 25 MMtpy.

IOC has also announced plans to invest approximately $25 B to reach net-zero emissions from its operations by 2046. The company's plan centers primarily on refining and petrochemical plant operations, which account for 97% of IOC's emissions. The company will use renewable energy to fuel its capacity expansion, along with building green hydrogen plants at its refineries.

PT Kilang Pertamina International (PT KPI) is developing a second phase of the Trans-Pacific Indotama Olefin Complex Development Project. The complex is being built in Tuban Regency, East Java, Indonesia. According to Pertamina, this stage includes the construction of a naphtha cracker that will feed downstream units to produce 1 MMtpy of polyethylene and 600,000 tpy of polypropylene (PP). These petrochemical production units are scheduled to be completed in 2024.

Thaioil plans to complete its Clean Fuels Project in 2023. Designed to expand and upgrade the Laemchabang plant in Chonburi province, Thailand, the nearly $5-B project will enable the refiner to produce Euro-5 fuels. The project will also increase the facility's refining capacity by 125,000 bpd to 400,000 bpd.

Bharat Petroleum Corp. Ltd. (BPCL) has announced plans to build two new petrochemical plants in India. BPCL will build an ethylene cracker at the Bina refinery Madhya Pradesh and a PP plant at the Kochi refinery in Kerala. Both projects are expected to be completed in 2026.

To mitigate costly imports of refined fuels and petrochemical products, **PetroVietnam** has proposed a plan to develop an integrated refining and petrochemicals complex in Long Son commune, Vung Tau city, Vietnam. The $19-B project will be developed in two stages. Stage 1 consists of a 12-MMtpy–13-MMtpy integrated refinery and petrochemical complex. Once completed, the complex will produce 7 MMtpy–9 MMtpy of petroleum products and 2 MMtpy–3 MMtpy of petrochemicals. The second phase will increase petroleum products output by 3 MMtpy–5 MMtpy and petrochemicals production by 5.5 MMtpy–7.5 MMtpy.

According to PetroVietnam, the feasibility study on the project will be completed in late 2023. A final investment decision (FID) is scheduled for Q1 2024, with EPC contract awards from 2024 to late 2027.

Debo is building a 200,000-tpy bio-methanol plant in China. The full volume of the produced green bio-methanol will be used by **Maersk;** the company will use the product as a shipping fuel. In an effort to decarbonize marine shipping, Maersk has ordered more than 10 large, dual-powered TEU boxships—the ships can burn methanol or conventional low-sulfur fuel for power. Debo's bio-methanol plant is scheduled to begin operations in Q3 2024.

Lummus Technology will supply its CATOFIN and Novolen technologies for two units being built by **Fujian Eversun New Material Co.** in Fujian province, China. Lummus will provide its CATOFIN technology for a 900,000-tpy propane dehydrogenation unit and its Novolen technology for an 800,000-tpy PP unit being built at Fujian Eversun's complex. Lummus' scope includes the license of both technologies, basic design engineering, training, services and catalyst supply.

Viva Energy Australia has awarded **McDermott** a front-end engineering design (FEED) contract for its ultra-low-sulfur (ULS) gasoline project in Australia. McDermott will provide FEED for a new modularization unit to increase the production of ULS gasoline at Viva Energy's Geelong refinery in the Australian state of Victoria. The ULS fuel will lower sulfur content to 10 ppm, which will enable Viva Energy to adhere to new fuel quality regulations that will take effect in the country by 2025.

Chennai Petroleum Corp. Ltd. has formed a JV with its parent company **IOC** to build a nearly $4-B refinery in India. Located at Nagapattinam in the state of Tamil Nadu, the 9-MMtpy refinery will be built after the JV dismantles the existing 1-MMtpy Cauvery Basin refinery located there. The new refinery will produce refined fuels that adhere to India's Bharat Stage-6 fuel quality standard. HP

An expanded version of Construction can be found online at www.HydrocarbonProcessing.com.

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Expanded polystyrene manufacturers incorporate RTO technology to meet clean air regulations

Anyone who has encountered foam clamshells for restaurant takeout food, white or green "peanut" packing to cushion shipments, or those thick foam blocks for protecting boxed furniture is familiar with expanded polystyrene (EPS). In use since the 1930s, EPS continues to gain in use around the world in applications from surfboard cores to roadways and building materials. Mordor Intelligence has estimated the 2021 EPS market at 8 MM metric tpy (impressive for a substance that is > 95% air), with a ~5% compounding annual growth rate (CAGR) through at least 2027. However, EPS production does carry certain environmental costs.

Ship & Shore Environmental (S&SE), a multinational environmental pollution abatement and energy solutions firm, now offers steam-generating thermal oxidizer (STGO) equipment (FIG. 1) that can help mitigate these costs to help better meet environmental regulations and potentially qualify for "green" manufacturing incentives.

The pentane problem. EPS begins as a collection of polystyrene beads impregnated with a "blowing agent" that allows the beads to expand (with steam) up to some 40x their original size. These expanded foam beads then get pressed and molded into a desired shape for eventual use. EPS is lightweight, protective, and a cost-effective thermal insulator.

FIG. 1. Ship & Shore Environmental's Steam Generating Thermal Oxidizer (SGTO).

Very often, pentane is used as the blowing agent in EPS. Pentane compounds are frequently used as fuels and solvents. However, improperly managed pentane has a host of well-known health impacts, including damage to the eyes, skin, lungs and nervous system. It can also contribute to poor air quality (via ozone damage), which causes another chain of health effects. As a result, governments and industry manufacturers alike have embraced EPS treatment regulations. Only with proper handling and processing will EPS remain viable, responsible, profitable and feasible for recycling.

EPS fabrication requires highly customized abatement systems able to handle high concentrations of volatile organic compounds (VOCs), including pentane. Specific requirements will depend on regional environmental regulations and the nature of the EPS operation or environment generating VOCs. These can include:

- Bead storage areas
- Bead dump to hopper
- Pre-expander operations
- Fluidized bed dryers
- Block/shape mold releases
- Vacuum system exhaust
- Pre-puffed silo storage
- Heated aging rooms.

Every such pentane/VOC nexus has its own emissions characteristics that will shape any abatement equipment design. One size does not fit all, and performing that customization in a safe, effective manner requires considerable expertise.

S&SE and the STGO solution. For more than two decades, Ship & Shore Environmental has specialized in the design, construction and deployment of high-efficiency abatement systems tailored to a broad range of industries. As environmental, social and government (ESG) mandates and VOC emissions regulations expand in tandem, S&SE has emerged as one of the U.S.'s top resources for abatement solutions, as durable and reliable as they are capable of containing operational expenses. Approximately 90% of EPS air pollution control systems throughout the country have been engineered, installed and maintained by S&SE.

Most of these S&SE solutions for EPS pentane emissions have been based on regenerative thermal oxidizer (RTO) technology, which has proven to be the preferred pentane abatement technology to present. Most RTO systems combine combustion and heat recovery chambers to achieve a 1,500°F operating temperature suitable for destroying 98% of VOCs. Exhaust heat can be captured and repurposed by the business, such as for building air and/or water heating—this recapture often qualifies for rebate incentives from local energy utilities, with some payouts even reaching six figures. S&SE RTOs operate from either a minimal amount of natural gas or even from the pentane contained within the industrial operation, making the abatement process self-sustaining.

S&SE has now improved on its RTO technology with its steam-generating thermal oxidizer (SGTO) innovation. In essence, an SGTO is a thermal oxidizer built into a steam boiler. The SGTO also sustains at 1,500°F for at least 0.5 sec to destroy pentane and other VOCs. However, radiated heat transfers via convection to a set of boiler tubes, which then produce hot water or steam. Depending on the application and environment, an economizer installed in the exhaust stack can capture this waste heat and convert it to energy, which can then be used for the SGTO or the business running it.

According to the company, any industrial plant that uses steam, hot water or hot oil for process heating while also working with VOC abatement requirements can benefit from S&SE SGTO solutions.

Next-generation machine visualization solution differentiates OEM systems, improves user operations

Machine builders in any industrial application can now use Emerson's PACSystems™ RXi HMI (FIG. 2), a next-generation machine visualization solution designed to help set its systems apart for customers. The new system easily helps users overcome the limitations of lower budgets, fewer people and higher productivity demands. This highly intuitive human-machine interface (HMI) addresses the needs of today's industrial workforce with easy-to-use, smartphone-like graphical displays without sacrificing rugged, industrial performance.

Unlike traditional resistive displays, PACSystems RXi HMI is designed with projective capacitive touchscreen technology that allows users to interact with the visual display with 10-point multitouch capabilities like swipe, pinch or zoom to move to the next screen or expand a chart, enabling easy operation by a wide range of personnel with varying levels of training and experience.

PACSystems RXi HMI comes preloaded and pre-licensed with the advanced Movicon™ WebHMI software, so the device is conveniently ready to operate out of the box, saving customers time. PACSystems RXi HMI is HTML5-ready, which allows users to collaborate from anywhere so operations, management and maintenance teams can all view the same screen at the same time, no matter the distance. This immediate sharing of information and access to expertise reduces maintenance costs and improves productivity.

In addition, customers will value the faster access to data-based operational insights to maximize overall equipment effectiveness. The PACSystems RXi HMI, with Movicon WebHMI at its core, is IIoT-ready for data analysis, troubleshooting and diagnostics, placing the operational insights customers need at their fingertips. A data trending tool provides a clear snapshot of productivity and quality. The SQLite database tool and PAC analyzer help users troubleshoot problems and minimize downtime. In addition, it provides extensive protocol support with OPC UA for better data contextualization and MQTT for easy cloud connectivity—the solution goes far beyond visualization.

PACSystems RXi HMI protects against both physical and digital risks. It offers protection in wet applications with certifications for both high-pressure water jets and marine use with an IP66 water resistance rating, and is approved for use in a wide range of temperatures from –20°C–65°C. In addition, the device is resistant to chemicals, impact, scratches and dust. It is also designed in accordance with IEC 62443 Global Automation Cybersecurity Standards to support end users' overall digital security strategy.

General duty single cartridge seal

Chesterton, a global leader in equipment sealing and reliability, has released its newest mechanical seal product: the 1510 general duty single cartridge seal (FIG. 3).

Accompanying the recently released 1810/2810 high-performance seals, this seal represents another foundational component for Chesterton's cartridge seal portfolio and future mechanical seal business. Designed with a compact cartridge profile and utilizing the Chesterton T.A.B.S. (Tapered Adjustable Bolting System) field proven on the 155 and 442 split seals, the 1510 is designed to fit and install easily on process equipment throughout industry. The unique resettable centering strap allows for impeller adjustments even after the seal has been fitted. Incorporating Chesterton's five key features of good mechanical seal design, the 1510 sets the new standard for general duty cartridge seals.

Rupture disk improves process performance and efficiency

OsecoElfab has launched the technically advanced LoKr reverse rupture disk for chemical process and petrochemical plants. The new disk design delivers a best-in-class flow resistance factor, or KR, to maximize pressure-relieving performance while delivering superior reliability and extraordinary service life.

The LoKr represents the next generation of design and engineering in pressure relief technology. The disk's architecture

FIG. 2. Emerson's PACSystems™ RXi HMI, a next-generation machine visualization solution.

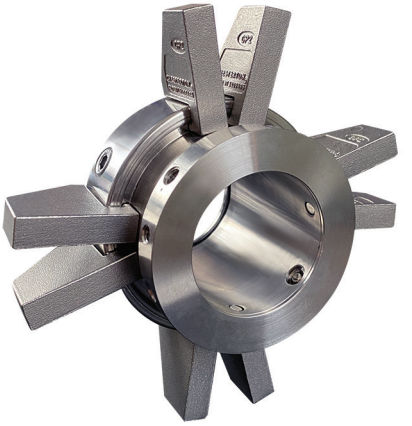

FIG. 3. The Chesterton 1510 general duty single cartridge seal.

has been refined and optimized to improve performance in three key areas: keeping pressure drops in relief lines to an absolute minimum, providing maximum reliability and accuracy, and being suitable for the widest range of pressures, temperatures and line sizes possible.

The reverse-buckling disk combines a dimple on the disk with an innovative knuckle on the holder to offer full-bore opening with exceptionally accurate burst ratings. This enables a higher flowrate on burst than previously possible, demonstrated by the disk's low KR value of 0.22. This makes it easier to keep pressure drops across the relief line below 3%, when the LoKr is used in relief valve isolation. Process plants can continue to use smaller piping diameters with no loss of performance or efficiency, even at low flowrates.

LoKr offers superior reliability, a wider size range, a lower KR and improved safety compared to other designs currently available, according to the company. Designed to ASME XIII standards and certified with a UD stamp at a best-in-class KR value of 0.22, the LoKr is now available. HP

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The benefits of homomorphic encryption: A technological enabler for digital services to operations

Among the cryptographic technologies under development in various industries, homomorphic encryption (HE) possesses the attractive feature of allowing computation within the encrypted domain. Encrypted data cannot only be transferred and stored, but also used in the secure encrypted state. This state-of-the-art technology has evolved rapidly over the past decade with new breakthroughs every year since the first functional implementation in 2009. The technology has already been proposed for face recognition and in other domains where a high level of privacy is mandatory.

This article presents the main principles of HE, as well as the benefits that can be leveraged from this technology for the energy industry. It also provides information on the specific challenges faced in its implementation in our industry.

With the advent of Industry 4.0, a company's digital transformation embeds the exploitation of all available plant data to enhance monitoring, planning and optimization of operating parameters, maximizing the production rate at minimal cost. As an example, predictive maintenance solutions analyze performance and operating data from rotating equipment to detect any potential failure as early as possible using tools that combine machine-learning and artificial intelligence (AI) methods.

Often overlooked or underused, plant operating data constitutes an important and full-fledged asset that should be properly valued and secured internally or by third-party expertise.

In cases where data cannot be used internally and must be transmitted to an external service provider, data owners can be reluctant to share such confidential information in plain text with a third party for various reasons. This data can include protected intellectual property on the company's facilities, financial statements and results, and sensitive information with national security implications.

How can we guarantee a company's confidential data can be outsourced safely by certifying the content will not be "readable" by a third party in charge of its processing?

There are many competing technologies for data encryption. Among the main technologies, symmetric cryptography, such as advanced encryption standard (AES), and asymmetric cryptography, such as RSA or El Gamal, are widely used when navigating the web and for online payment. These cryptography algorithms are recognized for their fast computation time while providing an important level of security for data at transit and data at rest. However, data must be deciphered to be of any use in computation. As such, these algorithms are not fit for the use of confidential data by a third party.

Therefore, other algorithms are proposed for more advanced applications. As an example, multiparty computation (MPC) is adopted in digital asset protection and cryptocurrency. Though MPC allows the performance of mathematical operations on encrypted data, the result of the computation can be available to all parties. One of the specifics of the MPC scheme is that it also requires an elevated level of cooperation between parties, as the computation algorithm must be shared.

When compared to these technologies (i.e., classical cryptographic algorithms AES or RSA), HE adds computation confidentiality to data confidentiality at transit and at rest ensured by AES or RSA. It also alleviates the communication overheads introduced when using MPC.

Enabling safe and secure computations. HE is a form of encryption that allows computation on encrypted data, generating an encrypted result that, when decrypted, matches the result of the operations as if it had been performed on plain text. This means encrypted data can be securely and safely outsourced for computation by third parties.

In a real case example, "Alice" will encrypt and transmit her sensitive data to "Bob," who is in charge of data analysis and computation. The homomorphic property of the encryption algorithm allows Bob to perform these calculations directly on the encrypted data and obtain an encrypted result. The latter is an encrypted version of the result that would be recovered if Bob's computation were done directly on Alice's plain texts.

As shown in **FIG. 1**, Alice receives from Bob the encrypted results of the operation. Alice uses the decryption key to recover the results and then exploit them. Only Alice, owner of the private key used for decryption, will be able to read and understand the results of the calculation performed by Bob.

Bob, in charge of the data computation, will never have access to the data in plain text, neither input nor calculation results. On the other side, the details of calculation algorithms remain Bob's intellectual property and are not disclosed to Alice.

HE can be symmetric or asymmetric. In the first case, the encryption and decryption keys will be the same secret key. Meanwhile, in the second case, the encryption and decryption keys will be different but related. The encryption key is also called

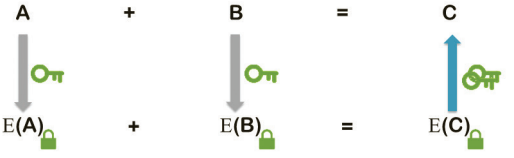

FIG. 1. Principle of homomorphic encryption.

the public key and is shared with any party. The decryption key must remain private and serves only for data decryption. The owner of the private key is the only entity capable of decrypting the data encrypted with its corresponding public key.

The HE idea was introduced in 1978 by Rivest, *et al.*,[1] but no true fully HE scheme was developed for years. However, research and improvement have increased in the last decade. In 2009, Gentry[2] made a breakthrough by specifying the first fully HE scheme allowing summing and multiplying ciphertexts. Many encryption schemes were then specified and regularly optimized with the recognized 4th generation of the FHE schemes (CKKS scheme in 2016). With these improvements, it has been calculated that the speed of HE execution was increasing by eight times every year between 2011 and 2021.[3] This fast-track improvement of the technology has made it applicable to daily life use in recent years.

Examples of already implemented HE include:

- Critical infrastructure monitoring, such as electrical network load and balance
- Health data, including sharing private medical records for statistical studies
- "Pay as you drive" insurance with an attached analytical device that gauges driving style
- Passport face recognition at the airport.

In its current state, HE supports the basic mathematical operations of summation and multiplication. This opens a wide variety of applications, as these two operations are sufficient to define a large spectrum of algebra.

However, HE requires significant computational resources to perform operations within the encrypted space. The computation time of a single simple equation may take a few seconds to perform—this is the cost for the high privacy proposed by HE.

Due to these limitations, the use of HE must be carefully investigated to ensure selecting the most adequate HE algorithm for a given application. In the energy industry, this technology is of particular interest in the use of production data, which are usually considered as extremely sensitive information as their disclosure may impact companies' share or product prices. This sensitivity of production data is a real showstopper for the implementation of digital services to operations, as all inputs to these services must remain within the company's operating information management ecosystem. Therefore, subcontracting specialized computation to vendors or contractors is not considered an option by operating companies.

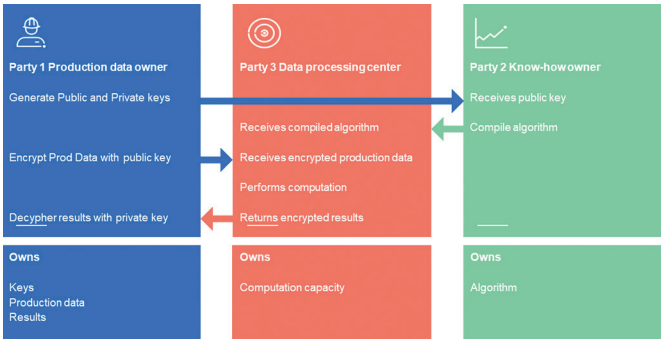

FIG. 2. Three-party confidentiality scheme.

A three-party scheme. Using HE, it becomes possible to utilize a scheme that includes up to three different parties in a straightforward way. The first party is the industrial site/owner of the production data. This first party is interested in using external expertise resources but does not wish to disclose the production data. The second party is a vendor or contractor that has developed internal expertise and is willing to provide results in a near real-time manner to the first party; however, the second party wishes to retain its intellectual property on the knowledge. Lastly, the third party possesses huge processing capabilities and is willing to host the near real-time service. This overall scheme is outlined in **FIG. 2,** which illustrates how energy industry benefits can be leveraged from the HE to run near real-time online processes and operations analysis without disclosing production data.

The protocol can be declined in several two-party schemes, considering that two of the three mentioned parties are the same. Each of these two-party schemes would serve different purposes, such as confidentiality during cloud computing or confidentiality of algorithms and data.

The capacity to treat production data in near real time while maintaining the privacy of the production data is quite appealing to the energy industry, and enables the development of digital services based on data reconciliation and analysis. However, even if the technology is answering some of the key questions for this kind of service, it must still prove effective in the context of the energy industry.

Partnership in development project. The authors' companies partnered in a development project to evaluate the application of HE to a realistic problem in the energy industry. A case study was selected regarding the monitoring and production tracking of a debutanizer column. A process dynamic simulation model of the asset was developed providing the data from the industrial site. In addition, some computation to be applied through the homomorphically encrypted program was defined.

At the early stage of the project, two key issues were soon highlighted. The first issue is that results from the homomorphic calculations must be contextualized in time for a good understanding of the results. The second issue deals with the kind of data that is generated in our industry.

For contextualization, the issue was easily overcome by adding a time stamping on the data. Therefore, even during a steady operation of the plant that would generate two identical sets of process conditions otherwise, the external observer would not witness status quo information.

In the energy industry, engineers and operators are familiar with working with a broad range of real values to characterize plant behavior. The common feature for all already developed applications is that the encrypted input data are minimal in terms of digital space. They are mostly coded over short integer data when they are not binary. With HE, the computation time will be related to the number of bits required to represent the information. An initial assessment resulted in several minutes for a sum product calculation when encrypting bits separately using a binary plain text space. Further development with encryption schemes supporting modular arithmetic with large plain texts brought a sharp decrease in calculation time (from

several minutes to a few seconds) without loss of significance.

One of the functions assessed during the research was an economic evaluation of the debutanizer performance. This evaluation was made from "customer" encrypted production data and from clear parameters on product prices that can be set from market prices.[4,5]

The encrypted inputs are:

- Feed mass flow: *F1*
- Fuel gas mass flow: *F2*
- Liquefied petroleum gas (LPG) mass flow: *F3*
- Stabilized naphtha mass flow: *F4*
- Hot oil mass flow: *F5*
- Hot oil inlet temperature: *T1*
- Hot oil outlet temperature: *T2*.

The clear market prices inputs are:

- Unstabilized naphtha $/t (ton): *K1*
- Fuel gas $/t: *K2*
- LPG $/t: *K3*
- Stabilized naphtha $/t: *K4*
- Hot oil properties: *K5*.

The output *O1* (in $) is expressed as (Eq. 1):

$$O_1 = [F_2 \times K_2 + F_3 \times K_3 + F_4 \times K_4 - F_1 \times K_1 - F_5 \times K_5 \times K_2 \times (T_1 - T_2)] \times (\text{Sample Interval} / 3{,}600) \quad (1)$$

The *O1* computation time with the BFV encryption scheme from the Microsoft SEAL library was 0.033 sec when encrypting large plain texts (~32 bits long). Note: Two pre-analyses allowed the authors' companies to fix the size of their plain texts and choose the suited HE algorithm for *O1* computation (i.e., to choose the BFV encryption scheme from the Microsoft SEAL library). First, *O1* was computed over clear *real* numbers to get the expected output values and their ranges. Then, it was computed over clear *integers* obtained by rescaling the clear real inputs. Computing *O1* with rescaled integers introduced a loss of precision. The rescaled integers size was fixed to ensure obtaining a result with two significant digits. The companies ended up working with clear integers longer than 32 bits. Then, as *O1* computation consists only in addition and multiplication of integers, the partnership chose to use an HE scheme supporting modular arithmetic with large inputs, such as BFV in the Microsoft SEAL library or BGV in IBM Helib. That is, the companies did not choose to use libraries working with binary plain texts by encrypting separately the bits of inputs (such as the TFHE library), as *O1* computation in that case would take around 1 min.

However, with the Microsoft SEAL implementation of the BFV scheme used to reach this performance, it was not possible to perform comparison on real numbers that also were part of the evaluation. Therefore, the final demonstrator integrated two different implementations relying on two different HE schemes, one with a TFHE scheme and a binary plain text space and the other with the BFV scheme and covering large numbers to minimize computation time. The functions evaluated with TFHE enclosed an encrypted comparison. The functions computed with BFV required only additions and multiplications. The outcome of the work performed on the demonstration test case was that the 20 tested functions were evaluated every 10 sec without lag with a standard 4-core server.

Takeaways. The research work performed on the applicability of HE schemes in the energy industry proved successful thanks to the cooperation between the authors' companies and their collective knowledge of industry and research. At the start of the project, the forecast of computation time was unsatisfactory and seemed to be a showstopper in the current state of the research. Creative solutions were found to overcome this initial assessment and ended in a workable demonstrator hosted in a standard virtual machine.

Online digital services in the energy industry can be made easier from a contractual standpoint with the use of HE. It secures actors in their respective confidential production data and intellectual properties for this kind of project.

HE extends a plant optimization program performed on selected historical data to a near real-time application. Algorithm crafted from the historical data in traditional ways can be converted into an online homomorphically encrypted application that continues providing operations information and advice. HP

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Following his initial training as a process and chemical engineer at the Ecole Nationale Supérieure des Industries Chimiques in Nancy, France, in 2000, **FABRICE REY** specialized in process dynamic simulation applied to the energy industry. He worked for 14 yr at a company dedicated to process dynamic simulation, where he developed his skills working as a model developer, a lead engineer, a project manager and as a technical sales engineer. Rey has more than 20 yr of experience gathered on five continents, and he joined Technip Energies as Lead of process dynamic simulation activities to develop the company's internal capabilities as part of the Expertise and Modeling department.

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AYMEN BOUDGUIGA is a Senior Researcher at CEA, and works on fully homomorphic encryption applications to neural networks. Previously, his investigations and work have included topics related to autonomous vehicles security or mobile device authentication. Dr. Boudguiga earned a PhD in 2012 in computer science from University Pierre and Marie Curie in Paris, France.

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Optimization of ethylene in the processing of hydrocarbons

The measurement of moisture or humidity is very important in most industries, including the petrochemicals sector. Excess moisture in instrument air can cause pipes to rust or pneumatic equipment to malfunction. Controlling the moisture concentration in process solvents helps maintain quality and prevents the formation of corrosive acids (e.g., hydrochloric acid). High moisture levels can impact the energy content of natural gas, so it is critical for many process applications to have a reliable moisture measurement system in place to ensure smooth operations.

The ethylene process. Moisture measurement is essential in the optimization of ethylene production. Ethylene is the world's most produced chemical, and its largest uses are for polyethylene, vinyl chloride monomer (ultimately polyvinyl chloride) and ethylene glycol.

Ethylene can be obtained through steam cracking, using a hydrocarbon feedstock such as ethane, naphtha or gasoil. Ethane feedstock is considered an ideal feedstock, since it has a higher selectivity and yield of ethylene than propane, butane or heavier feedstocks (like naphtha or gasoil). This results in simpler processing and reduced capital costs.

Ethane is diluted with steam and heated to 759°C–950°C (1,398°F–1,742°F) in a furnace. Steam cracking is an endothermic process that breaks up large molecules into smaller ones. The steam cracking effluent is sent to different separation and purification units, which allows for the recovery of ethylene and other products, such as methane, ethane, propane and propylene, which are also cracking remnants.

After ethylene recovery, a purification process is necessary to obtain the desired ethylene quality. One of the main objectives of the purification process is to reduce the presence of water necessitated by the handling of ethylene at cryogenic temperatures. Ethylene must be pressurized and cooled to obtain the liquid ethylene that facilitates transportation in specially built tank cars to storage tanks, or through pipelines to different plants. A compression and cooling process is needed to obtain cryogenic ethylene. Moisture in ethylene forms hydrates that are likely to block exchangers and lines or reduce flow performance, causing significant and costly operational issues.

Moisture measurement. Previous technologies used for moisture measurement in ethylene gas were sensitive to external temperature and process pressure changes and were not sensitive enough to small variations in the process that the operators required. The evaluation of a quartz crystal microbalance (QCM) trace moisture analyzer in ethylene gas was undertaken by the co-author's company. The primary objectives included seeing how this technology responded to external temperature changes and testing the sensitivity of the analyzer to small variations in the process.

Given the variations in ambient temperature that some sites have throughout the year (–10°C to 50°C) and during a typical day (some day/night variations are greater than 10°C), the decision was made to verify this analyzer after it was installed, and to observe the performance in actual ethylene process gas that has very low concentrations of moisture. The variations in outside ambient temperature and process pressure were first analyzed to ensure that process moisture was not affected. Then, the temperature and known process changes were compared with the moisture measurements.

Sampling conditions. The sampling point was located at the outlet of the two ethylene dryer columns. Low-level moisture measurement best practices were followed by using 0.125-in. electropolished stainless-steel sample lines with electrical heat tracing, minimizing the distance (5.5 m) between the sample tap and the analyzer. Increasing the speed of response by reducing the sample volume in the sample conditioning system was

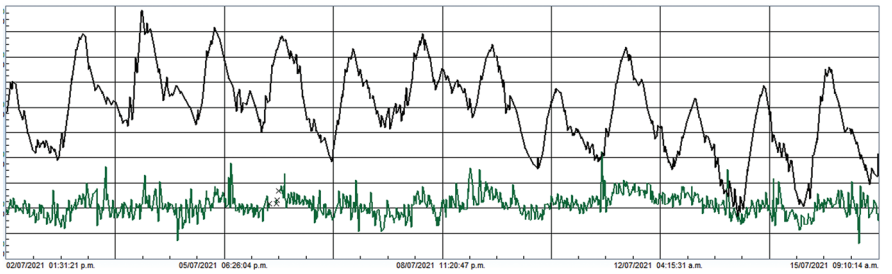

FIG. 1. Ambient temperature vs. ethylene temperature variations. The black line represents the OAT trend, and the green line is the process temperature at the input of both dryers.

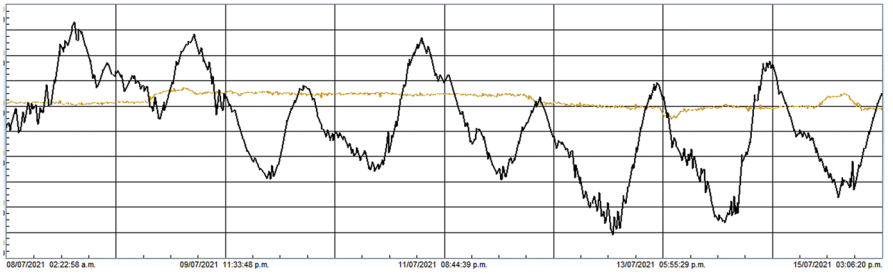

FIG. 2. Ambient temperature vs. process pressure variations. The black line represents the OAT trend, and the brown line is the process pressure at the input of both dryers.

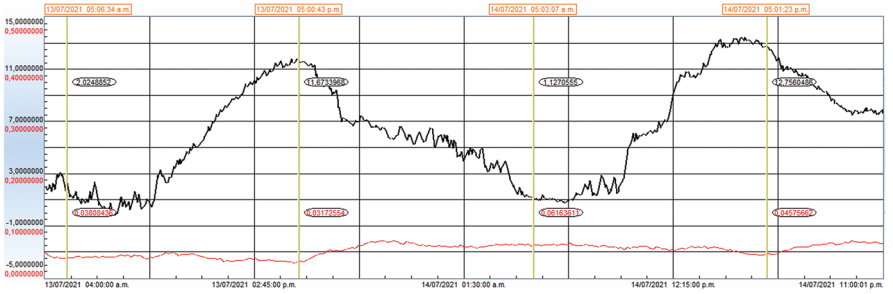

FIG. 3. Winter season trend. The black line represents the OAT, while the red line is the moisture analyzer measurement. The OAT range is –5°C–15°C, while the analyzer measurement ranges from 0 ppmv–0.5 ppmv.

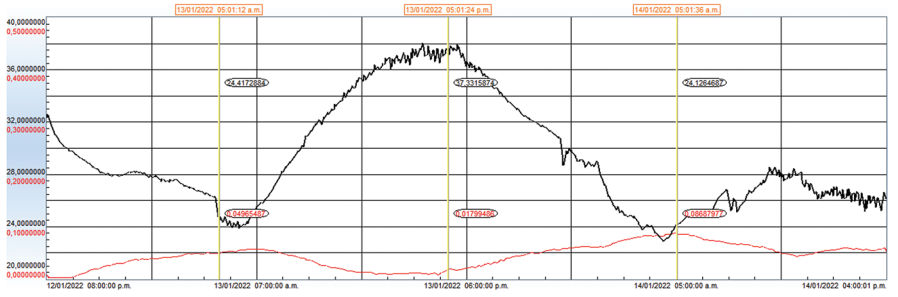

FIG. 4. Summer season trend. The black line represents the OAT, while the red line is the moisture analyzer measurement. The OAT range is 20°C–40°C, while the analyzer measurement ranges from 0 ppmv–0.5 ppmv.

executed by reducing the sample pressure to the required analyzer's sample inlet pressure as close to the sample tap (30 psig, 0.5 m) as possible. Characteristics of the analyzer included the following:

- Analyzer measuring range: 0.02 ppmv–100 ppmv by volume
- Moisture generator: 1 ppmv nominal
- Lower detectable limit: 0.02 ppmv
- Set output range: 0 ppmv–1 ppmv
- Accuracy: +/– 0.02 ppmv or +/– 10% of reading, whichever is greater
- Analyzer sample flow: 150 cm^3/min.

Outside temperature variations: Ambient temperature vs. ethylene temperature variations. The objective of this project was to observe how the outside ambient temperature (OAT) affects the temperature of the ethylene in the process. This analysis helped to determine if there was a large absorption or desorption of moisture due to changes in ambient temperature during the day.

The temperature sensor instrument used for the measurement was at the inlet of both dryers. The ambient temperature vs. the ethylene temperature variations is shown in **FIG. 1.** This period was taken as an example due to the significant day/night variation in OAT (from 0°C–14°C), with an average day/night variation of 8°C. Two observations were made in the ethylene temperature:

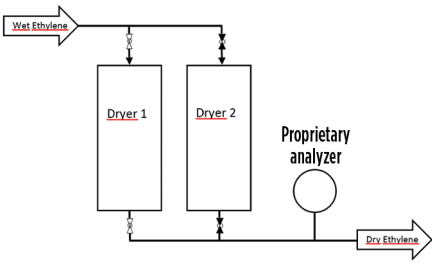

FIG. 5. A typical drying process system using two dryer columns.

1. Quick variations (average 0.3°C) due to analog signal noise and process temperature variations
2. Slow day/night oscillations related to OAT.

The relationship between day/night temperature and ethylene temperature depends on the rate and amount of variation in the outside temperature; however, the variation is less than 1°C on the ethylene temperature for every 10°C OAT.

It can be concluded that adsorption or desorption in this part of the process due to day/night OAT variations would not have a significant effect.

Ambient temperature vs. process pressure variations. The ambient temperature vs. the process pressure variations is shown in **FIG. 2.** The process pressure remains constant during the day/night. Therefore, process pressure is not influenced by the OAT. In conclusion, process pressure does not affect the measurements of the analyzer.

Moisture measurement variations regarding ambient outside temperature: Winter trend. QCM moisture measurement vs. OAT is shown in **FIG. 3.** In this winter period, the OAT normally stays low and stable. The trend period shown in **FIG. 3** was selected for its large day/night oscillation between 0°C and 13°C, with an average day/night variation of 11°C.

Despite the outside temperature variations, the measurement remains at values of 0.03 ppmv–0.07 ppmv. Twelve hours are indicated on the trend to show the peaks and valleys of the OAT.

It can be concluded that there was no evident relationship between the outside temperature and the moisture measurements. Moisture was at the lower end of the expected values.

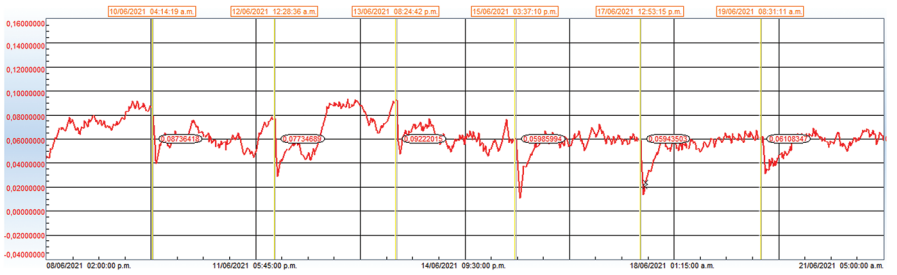

FIG. 6. Moisture measurement related to process dryer swapping. The red line indicates the moisture analyzer measurement, while the yellow lines indicate the moment of the dryer swap.

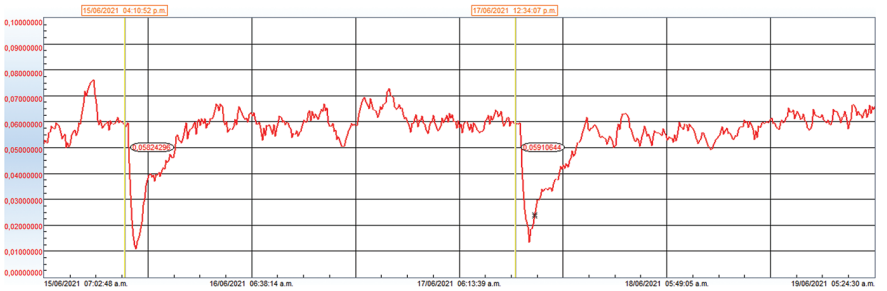

FIG. 7. Moisture measurements relate to process dryer swapping (two drying cycles). The red line is the moisture analyzer measurement, while the yellow lines indicate the moment of the dryer swap.

Summer season trend. In this summer period, the OAT ranged between 20°C and 40°C, with an average day/night variation of 14°C (**FIG. 4**). The measurement remained at 0.01 ppmv–0.08 ppmv. A small inverse relationship between the OAT and moisture measurements can be seen when OAT varies widely. Despite high variations in the OAT, moisture remained within the expected values.

Measurement variations regarding dryer swapping. The following analysis used small process variations to check the sensitivity of the analyzer. Using the QCM analyzer, small variations in moisture could be measured during dryer swaps.

In the two-column dryer dehydration system (**FIG. 5**), one dryer dehydrates the ethylene while the other is in regeneration. When one dryer becomes saturated with water vapor, it is swapped with the other dryer. The saturated dryer is then regenerated. The moisture analyzer was installed at the outlet of both dryers.

Moisture measurements related to process dryer swapping. A small variation in the dryer's moisture measurement (a drop of 0.03 ppmv) can be seen at each dryer swap (**FIG. 6**). This variation was expected, and it confirmed the sensitivity of this analyzer to process changes. The trend shown in **FIG. 7** extended two drying cycles to observe in more detail the moisture variations after each dryer swap.

Takeaway. QCM moisture technology has negligible influence due to the OAT. Some variations can be seen (no more than 0.02 ppmv) with day/night temperature changes (5°C–10°C). The lower detectable limit for this analyzer is 0.02 ppmv, which is consistent with what was observed.

In relation to the detection of low moisture values, this analyzer has proven to be very sensitive to small variations in the process. With the analyzer's internal National Institute of Standards and Technology (NIST) traceable calibration/verification system, it was possible to validate the analyzer's performance during testing. Because of this operation, the detection of moisture changes during dryer swapping has been transformed into valuable information for monitoring dryer performance and verifying ethylene quality. QCM technology has been proven to be suitable for this type of process. HP

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Shift focus to more open control technology

Plant control system modernizations that are necessary to meet today's goals and strategies often come with organizational hurdles. Modernization projects must be carefully planned, and traditional modernizations can be costly and time consuming. In many cases, hydrocarbon processors are operating with automation technologies that are often 20 yr–40 yr old and built on an input/output (I/O) infrastructure of tens of thousands of hard-wired elements.

Legacy equipment (including old wiring, terminations and infrastructure) presents hydrocarbon processors with a conundrum. Some plants do not mind maintaining their old architecture, but keeping that old hardware makes it difficult, if not impossible, to implement new control system technologies to improve process control and reliability. Conversely, if plant leadership chooses to remove old equipment, this process requires many hours and many people—and a significant capital expenditure, along with the cost of downtime accrued—while the modernization takes place.

For years, this conundrum has left hydrocarbon processors stuck in a difficult position: rip out everything and start from scratch, be forced into incremental and ineffective upgrades from the same automation vendor (whether the plant is satisfied with it or not), or continue to operate with legacy equipment that does not truly meet the plant's needs.

However, today's automation technologies are changing that paradigm. New I/O-agnostic control solutions provide an open architecture to accelerate modernizations—thus empowering project teams to be more flexible with capital expenditures and to eliminate downtime, while still delivering the technologies required to successfully carry their operations into and through the coming decades.

A modern, scalable, open solution. Modern control systems are much more effective, efficient and intuitive than their predecessors from decades past. However, trying to connect these new automation solutions to control technologies from the 1980s and 1990s is difficult, if not impossible. At best, it requires complex engineering that is fragile and difficult to support.

To address these and other issues, I/O-agnostic control solutions are designed to help plants implement modern control systems by using new control software and technologies of their choice, without the need to completely overhaul the automation equipment backbone. These solutions operate as a bridge between old equipment and the newest control system technologies.

Implementing an I/O-agnostic control solution enables plants to keep their existing I/O wiring, terminations and infrastructure in place. Project teams simply remove the existing controller and plug in a communications cable that runs through smart, high-availability I/O-agnostic interfaces to provide a new control system that is added to the old hardware (**FIG. 1**).

Consider a refinery with 30,000 I/Os controlled by 100 controller nodes. Overhauling the entire system via traditional modernization methods would take months or years, and it would require dozens of technicians spending countless hours tracing, replacing and terminating cables. However, with an I/O-agnostic interface, the plant can replace as little as one controller at a time, leaving all other existing I/Os in place. Facility personnel can leverage the most important advantages of the new control system, while replacing legacy infrastructure at their own pace.

Reaping the benefits of modern technologies. Many of the process and reliability technologies that were expensive or unavailable years ago have become standard manufacturing solutions today. Solutions such as alarm management software to eliminate alarm floods, built-for-purpose scalable and searchable human machine interfaces to foster better aware-

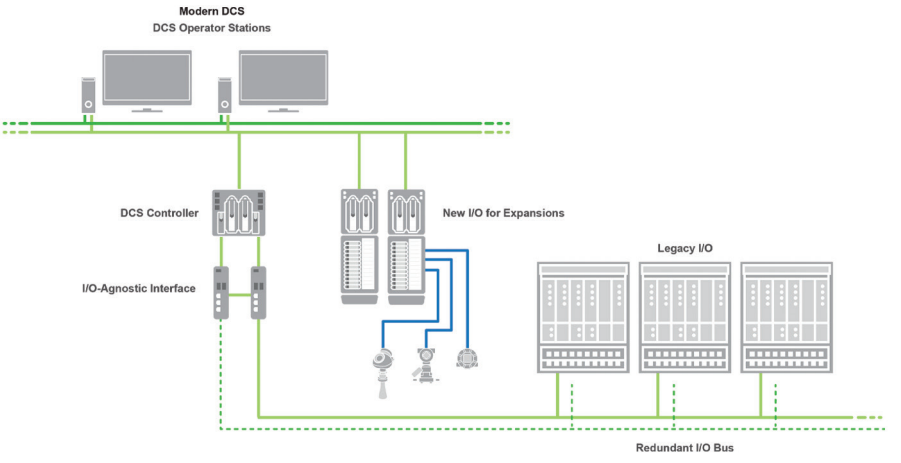

FIG. 1. An I/O-agnostic interface empowers plants to reap the benefits of new control technology without the added time and capital spending required for replacing old I/O infrastructure.

ness and control in the plant, and control performance monitoring for improved safety and visibility of plant operations are now considered best practices. However, plants operating legacy automation equipment are either unable to take advantage of these advances or are forced to implement and maintain complex engineering to support these new solutions (FIG. 2).

In today's environment of limited experienced personnel, plants need intuitive, integrated solutions to help run efficient operations—especially as they scramble to bring new-to-the-workforce staff on board. Modern control systems can bring in all the measurements, valve automation and reliability integration that plants need to help a new generation of personnel run the plant at peak performance—open solutions are the key to making this possible.

By taking the top layer off the control system and replacing it by using an I/O-agnostic interface, plants can add modern control systems and strategies with a wide variety of software applications capable of sending data wherever it is needed. They can easily provide that data to analysis, machine-learning and artificial intelligence solutions, and implement advanced process control strategies to capture expert knowledge.

This experience is exemplified in the case of a process manufacturer that recently developed plans to modernize its control system. Shortly after selecting the new control system and finishing the planning stages for the project, the company made a large acquisition that immediately generated unexpected capital constraints. Members of the modernization team could not simply abandon the project because they knew that the benefits of their digital transformation vision would be critical to the company's success. They also decided that they could not simply upgrade the existing control system and keep the old infrastructure in place, since the new control system that they had selected offered advantages that the old system could not provide.

Instead, the team members discovered they could have the best of both worlds by using an I/O-agnostic interface to connect their old infrastructure to the new control system. By eliminating the rip-and-replace strategy for the I/O infrastructure, the modernization team discovered it could reduce project costs by 40%, enabling the team to meet the new capital constraints, while still delivering the digital transformation improvements that would drive competitive advantages for years to come.

Achieving faster benefits with less risk. Whether project teams' modernization projects are bringing new capabilities, spinning up a previously decommissioned refinery to increase manufacturing capacity, or retooling and repurposing a terminal, these teams need solutions to help them deliver fast results without extended shutdowns of existing operations.

Traditional modernizations leave project teams with two options: shut down the plant or perform a complicated hot cutover. Either solution presents its own risks and requires a large number of staff on the ground spending many hours over an extended period of time—not an easy ask in an era of personnel shortages.

Leveraging technologies such as I/O-agnostic interfaces not only enables project teams to leave legacy I/O in place, but it also empowers them to customize modernization of automation technologies to simplify projects and reduce required personnel. With an I/O-agnostic interface in place, modernizations can be performed on a wide variety of scales: controller by controller, console by console, or even by individual facility areas. Using these technologies, project teams can transition key areas of the system in a tenth of the time required for traditional migrations and immediately start reaping the benefits of new control technologies (FIG. 3).

Moreover, the most advanced I/O-agnostic interfaces include technologies that make it easier to perform hot cutovers over time. Instead of having dozens of personnel working hundreds or thousands of hours trying to complete I/O cutover before project completion, teams can instead assign one person to cut over a single channel at a time after project completion by simply hitting a button in the software to switch from old I/O to new I/O when the installation is complete.

For one large manufacturer that relies only on pre-approved vendors to supply technology, I/O-agnostic interfaces provided many more options to improve performance. The plant's legacy control system was not performing to company standards, and its vendor was not an approved supplier for the technologies that the plant wanted to implement.

The project team identified that a move toward more open technology would enable the plant to upgrade to a new, fully

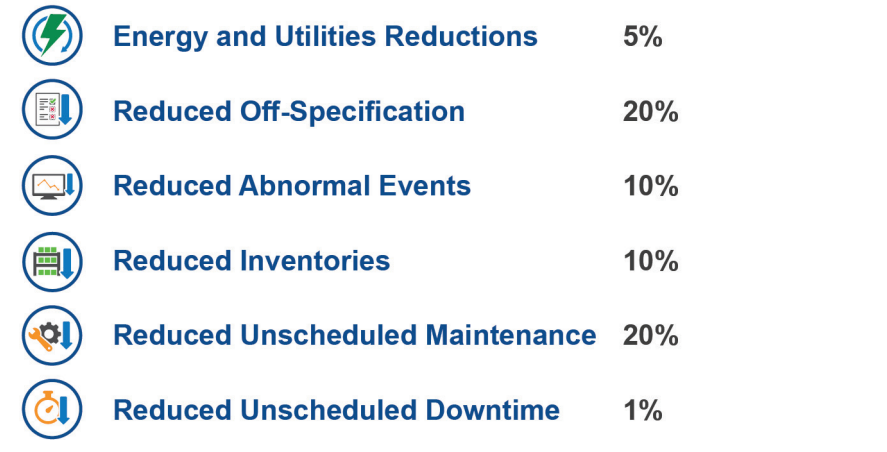

FIG. 2. The authors' company estimates significant production improvements from modernization projects.

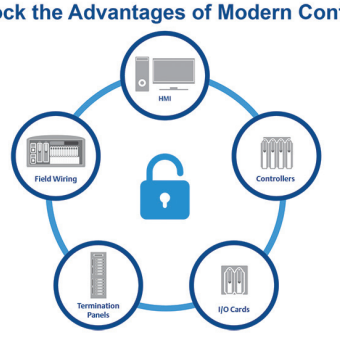

FIG. 3. Modern control technologies offer far more options for customized installation and control than legacy systems.

approved control system, as well as to a full spectrum of approved analytics, reliability and measurement equipment. This could be completed without the need to upgrade an unsatisfactory control system or to perform a full rip-and-replace procedure on the old equipment. The project team would simply strip the old controllers off the existing I/O and move to the control system of their choice, connecting it via an I/O-agnostic interface. Then, as time allowed in the coming years, personnel would gradually move the old I/O to new hardware, enabling a transition to optimum control with little to no downtime.

Maintaining capital flexibility. As hydrocarbon processors retool existing terminals and add new sites and trains to increase capacity, they are finding a need to add automation that leverages some of the existing infrastructure; however, plant personnel are also learning that such a strategy can quickly cause capital constraints. These teams need ways to better focus investments, allowing them to redirect capital to enable the updates they need without derailing other critical projects when budgets are tight.

Many of these plants are faced with difficult choices, as they will be forced to spend capital on automation in the next couple of years due to control system obsolescence. However, as they pull their capital plans together, modernization teams quickly discover that there is only so much capital to go around. These teams must balance the requirement to upgrade control technologies with additional mandated needs to process more product, refine more oil, expand and reopen refineries, and upgrade technologies just to keep running.

Control solutions with I/O-agnostic interfaces can help ease the pressure of constrained capital. This is one of the few places where a change is typically more cost effective than maintaining the status quo. Typically, the cost for supporting legacy control systems is high, and the support received is often poor, as few companies still have a deep bench of personnel capable of supporting old equipment. In contrast, agnostic interfaces to connect new control technologies to existing I/O are usually low cost—typically lower than the upkeep of legacy technology—and are designed to let plants start small and scale up as capital constraints allow.

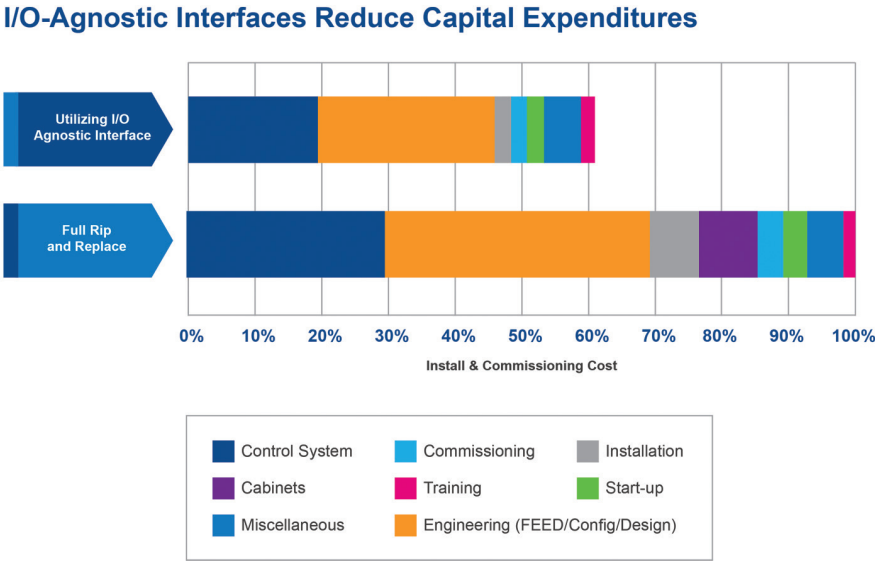

FIG. 4. Installed costs are significantly lower when using an I/O-agnostic interface vs. traditional rip-and-replace modernization strategies.

Moreover, because I/O-agnostic interfaces allow plants to keep existing I/O in place, they enable teams to postpone work that generates a large percentage of project cost. Once the interface is in, and the plant is up and running using new and more efficient control technologies, technicians can individually update I/O on their schedule while the plant is running—thus shifting what used to be a capital expenditure to the operations budget (**FIG. 4**).

One large producer hoping to address automation obsolescence across its entire enterprise discovered that it would never be able to procure sufficient funding to transition the hundreds of thousands of I/O points across its fleet as part of a capital project. However, implementing an open automation solution centered on I/O-agnostic interfaces would enable the organization to move all existing I/O to new control technology, and then put a plan in place to gradually transition its I/O backbone over the next decade, using existing personnel as part of operations. All plants would immediately reap the benefits of new control technology—a feat that seemed impossible, using traditional modernization strategies.

Improving modernizations and performance with open technologies. Meeting the world's needs for fuels and other petrochemical products requires an increase in efficiency, reliability and productivity, which is not possible when limited to most legacy control hardware. The answer is making the change to a new control system to unlock best-practice technologies but doing so in a way that does not require a rip-and-replace project that will generate massive downtime and strain capital budgets.

New technologies enable modernizations to deliver a fast return on investment, while simultaneously empowering teams to better manage capital costs and opening a wider array of options for available technology. Lifecycle costs for these new technologies are typically lower than what plants spend to maintain legacy equipment, and these open technologies empower plants to do more with less, both during and after modernization initiatives. HP

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Integrated remote operations drive collaboration and autonomy

Sensors, equipment and devices are becoming more intelligent, opening the door for autonomous operations, which is the ability for machines and processes to run while self-diagnosing and handling problems. When successful, the profit potential is clear. These benefits are gaining the attention of many process manufacturers; however, autonomous operation cannot be attained overnight.

As process manufacturers adapt to new methods of operating, they can transition toward autonomous operations over time and achieve higher efficiency, safer practices and improved sustainability (**FIG. 1**). This is made possible with increased integration throughout an enterprise, supported by advances in robotics, artificial intelligence/machine-learning (AI/ML), analytics and cloud technology, among others. The trend to operate facilities remotely from integrated operations centers (IOCs) is greatly enhanced by industrial autonomy and autonomous operations. IOCs are centralized business workspaces that provide an integrated view of an organization's people, processes and technologies to facilitate multidisciplinary collaboration and achieve new levels of operational excellence (quality, safety and throughput) and industrial autonomy.

This shift toward remote operations via IOCs enables process manufacturers to collocate multidisciplinary teams—such as operations, engineering, management and sales—in a common space that can be used to improve operational efficiency and decision-making, enhance asset reliability, reduce risks, lower costs and help maintain institutional knowledge. The concept originated in the oil and gas industry, with its numerous dispersed assets and field sites; however, in the age of digitalization, integrated operations have never been more relevant to all process manufacturers.

Integrated operation is more than just remote operation. It is common for process manufacturers to simply move their operations away from a primary processing facility or the field, and to then refer to the new operation center as "integrated." However, initiatives that only centralize control are more accurately referred to as "remote" operations because very little changes in terms of business processes.

The benefits of remote operations include centralized operational functions for multiple plants and assets located at a single hub. This makes staff management and scheduling more cost effective and improves personnel safety. But if process manufacturers stop here, they will limit performance improvement, and operators can lose situational awareness by their removal from the facility.

By going a step beyond remote to IOCs, process manufacturers can benefit from the creation of value-focused, cross-disciplinary teams, enabling transformational changes to traditional ways of working. Environments with multiple functional teams facilitate better brainstorming and lead to increased situational awareness and better process optimization insights, with improved information sharing speed, efficiency and effectiveness (**FIG. 2**).

This helps subject matter experts focus on overall plant conditions, looking beyond their single areas of expertise. An integrated view and approach to a process manufacturer's people, processes and technologies provide the freedom to expand workflows across multiple teams, without extensive time required to transfer assignments among various departments because silos are removed, thus improving knowledge sharing.

Robots, drones and AI/ML. The use of robots and drones can accelerate a process manufacturer's transition to unattended

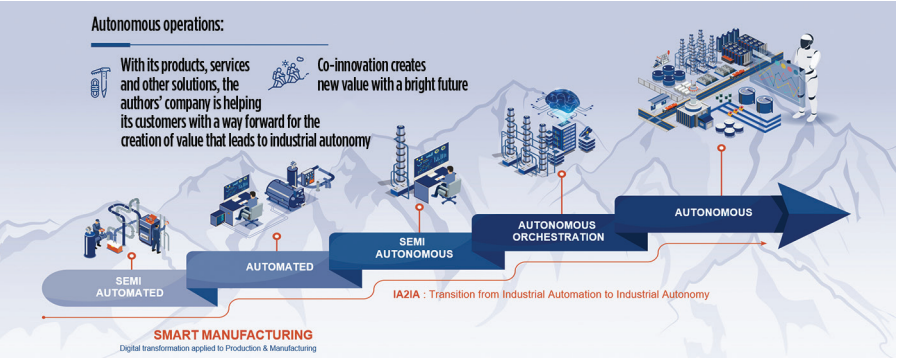

FIG. 1. There are several steps and levels on the journey toward autonomous operations, which is the transition from industrial automation to industrial autonomy.

autonomous operation because these advanced devices remove the burden from humans for executing many strenuous and repetitive tasks, especially in isolated and dangerous environments. Advanced robots and drones are equipped with AI to perform decision-intensive work and to improve their performance over time.

Robots and drones are available in a variety of form factors, each optimized for specific tasks, and, in some cases, capable of collecting information beyond the sensory limits of humans (FIG. 3). They are the eyes and ears of a plant in the wake of relocating operators to remote environments. In conjunction with smart cameras and other sensors, they provide a full range of sensory information across entire plants, which is transmitted to an IOC as the focal point for situational awareness.

Along with exponential increases in connectivity and devices, there has been a corresponding increase in data. New tools and mechanisms have been created to analyze, visualize and interpret volumes of data, and improved data management and analysis methods have emerged for storing, searching and accessing structured and unstructured data.

AI/ML is a basic principle of industrial autonomy, providing the decision support capabilities to improve asset reliability and production optimization, and to contribute to enhanced situational awareness in IOC environments.

Integrated operation is more than just remote operation. In remote operations, very little changes in terms of business operations. Integrated operations improve situational awareness and enable value-focused, transformational changes to traditional ways of working.

Modern manufacturing challenges. Most process manufacturers operate assets and facilities with dedicated resources unique to each site, but this approach fails to use central expertise and apply knowledge and lessons learned throughout the organization. This leads to suboptimal collaboration, decision-making, asset utilization, efficiency, productivity, situational awareness and safety, resulting in excessive downtime and high operational costs. This siloed approach also limits the capability to roll out cutting-edge smart manufacturing technology to enhance operations throughout the enterprise.

Another challenge for process manufacturers is worker expectations, which have increased with the maturation of digital technology. As a result, it is challenging for global companies to remain competitive, and to attract and better utilize top talent, when these employees must report to work in isolated or hazardous industrial facilities. Attracting new workers is more important than ever in the wake of the Great Resignation, in addition to longtime employee retirement issues. For less-prepared process manufacturers, the departure of these employees often equates to the exit of key operational knowledge.

Additionally, traditional industrial facilities are not set up to facilitate collaboration and communication, instead perpetuating silos of knowledge, as personnel rarely work outside their assigned teams. This can create misalignments in the ways various business units gauge the overall health of an organization, with operators seeing one reality, engineers another and managers still another.

Two additional areas of concern with older facilities are physical site safety and cybersecurity.

IOCs provide solutions. Consequently, more companies are pursuing IOCs to:

- Centralized IOCs drive best practices and lessons learned quickly to all plants under its stewardship
- Reduce the number of people and activities in production areas
- Remove silos between teams and foster cross-disciplinary collaboration across the business
- Facilitate remote monitoring of process parameters across multiple plants, with enhanced situational awareness
- Increase value opportunities by integrating more functions and/or assets of the organization.

IOCs help connect the sensor with the boardroom, ensuring that data collection is accurate at the source, while providing situational awareness at all levels of an organization. This shift, which collocates cross-disciplinary teams (such as operations, engineering, management and sales) in a common space, can improve operational efficiency and decision-making, enhance asset reliability, reduce risks, lower costs and help maintain institutional knowledge (FIG. 4).

The best-in-class IOCs are custom-designed office spaces where operations and support teams can collaborate easily on cross-functional workflows to maximize information sharing and thus allow for quick decision-making. IOC facilities include a secure control room, enabling real-time operational focus and ease of access to support teams. An IOC con-

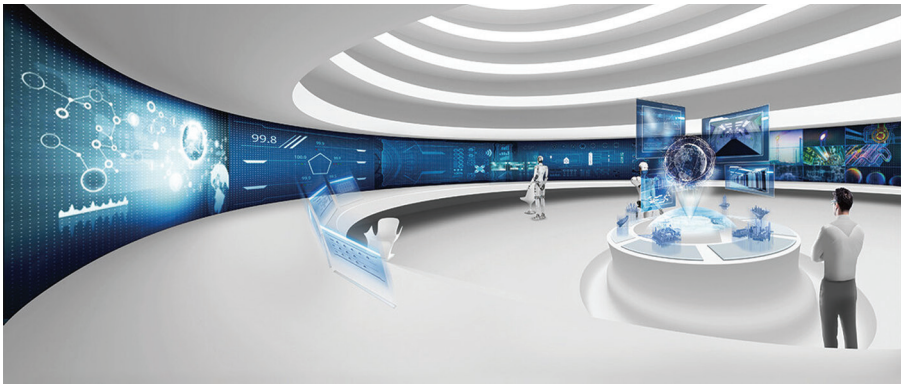

FIG. 2. IOCs collocate cross-disciplinary teams in a common space, thus improving operational efficiency and decision-making capabilities.

struction project should include office space and control room design, as well as support for collaboration technologies aligned with new ways of working, such as cross-functional workflow design and situational awareness solutions.

To begin design, process manufacturers must determine their overall operating objectives (e.g., whether the IOC will oversee assets regionally or globally) and then determine the expected business benefits from the IOC's approach. Facility layout is also critical, and process manufacturers must decide where each team will reside, determine a strategy for operating terminals and displays, and choose how to best facilitate collaborative business processes throughout the facility.

By modernizing physical footprints and enabling remote operations, process manufacturers realize a host of benefits. These projects remove operational personnel from many hazardous situations and environments, and they provide an opportunity for collaboration across functional teams. These collocated groups of operators, engineers, managers and others facilitate knowledge sharing more naturally throughout an organization, leading to ideas for more streamlined and efficient operation in addition to more organic goal setting and achievement (**FIG. 5**).

An IOC provides an integrated and consolidated view for safer and more efficient operations, especially when paired with advanced plant monitoring and control tools. For this to work, process manufacturers must invest in high-quality sensors and data collection mechanisms, thus reducing the need for physical facility rounds, while protecting plant assets and infrastructure from threats, both physical and cyber.

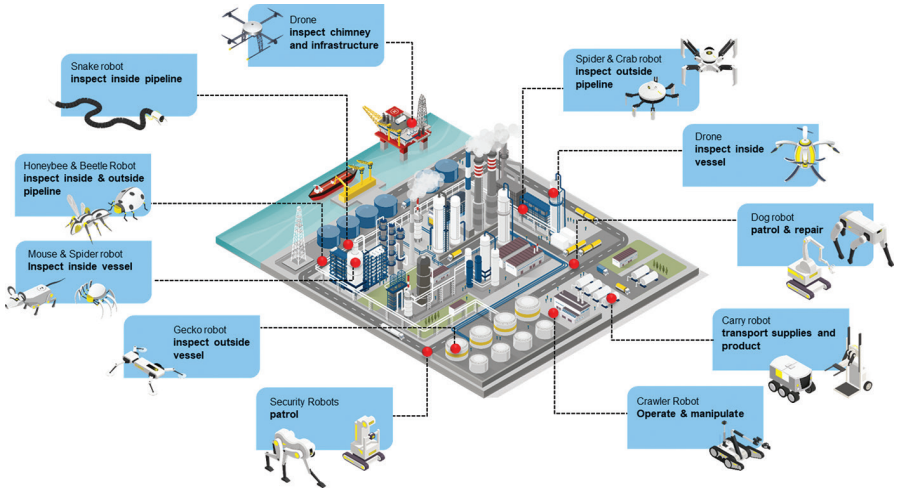

FIG. 3. The types of robots and drones are numerous, and, because of their specialization, they can often detect conditions and execute tasks that humans cannot.

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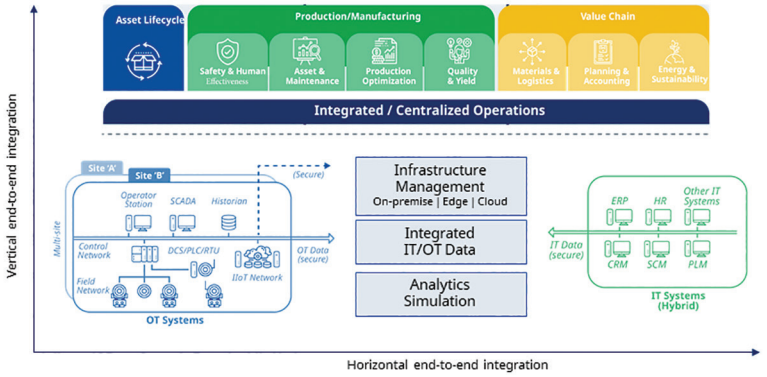

FIG. 4. IOCs combine many functional aspects of business and operations, providing abilities that these individual systems do not supply on their own.

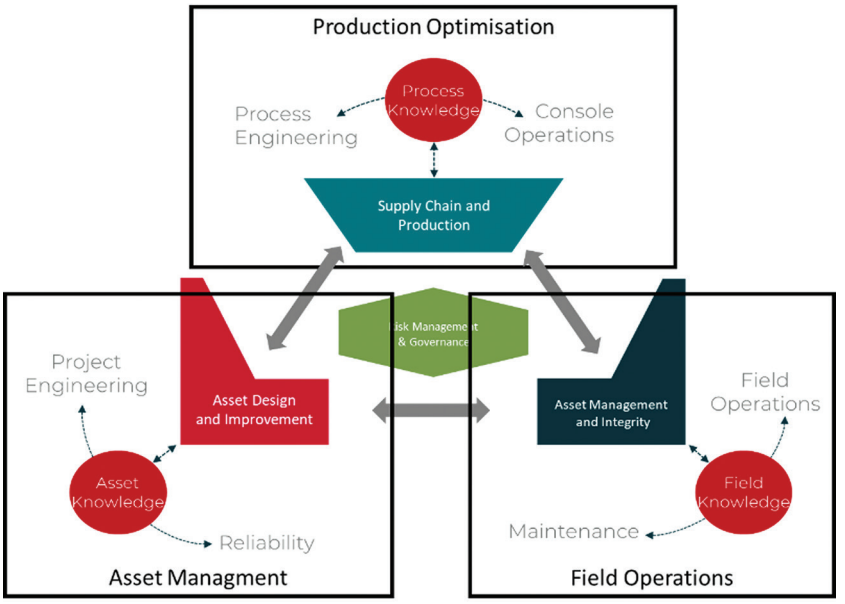

FIG. 5. An IOC operating model naturally facilitates knowledge sharing among groups within an organization, leading to better operational decision-making and increased efficiency.

On the technology front, IOCs are consistent with the operational technology (OT) trend of increasing AI and ML within facilities, moving toward autonomous operations wherever possible. Tools like augmented reality (AR) and always-on video feeds provide IOC staff with a view of plants and facilities in a virtual space, while robots can take on many routine inspections and equipment maintenance tasks.

Proper plant security, which includes both physical and cyber, is critical for the IOC approach to work, since threats and intrusions are fast lanes to unscheduled downtime. Secure and speedy network infrastructure provides the foundation for modern digital tools, such as condition monitoring and predictive maintenance algorithms, data analytics using digital twins, and advanced robotics software platforms.

Collaboration is key. An IOC supports a knowledge-oriented operating model by providing a cross-functional, collaborative work environment, and it maximizes information sharing to promote quick and high-quality decision-making. IOC design includes digital solutions to bring remote-operation field workers into regular and ad-hoc workflows, thus increasing situational awareness throughout an organization (**FIG. 6**).

For this to be effective, an emphasis must be placed on collaboration between IOC staff and personnel at plant sites. This requires a reliable OT infrastruc-

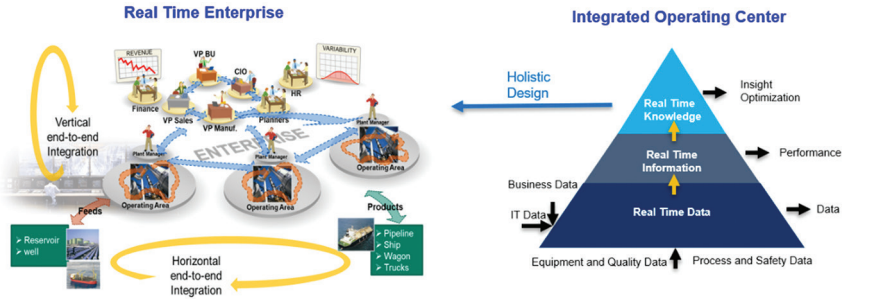

FIG. 6. IOCs, along with the digital tools powering them, help integrate remote-operation field workers and office staff into the same workflows to increase situational awareness.

ture. Without it, automation and autonomy cannot develop to the level required to move more monitoring, control and maintenance to remote operation.

When designing an IOC, experienced consultants can create turnkey solutions by considering a process manufacturer's needs in each of the following areas:

- **Operating philosophy and supporting infrastructure:** An organization's operating philosophy should align with corporate goals. Topics for consideration include remote or integrated operations over a regional or global scope.
- **Physical design:** The IOC's geographical and technological strategies should be considered, including physical location, building layout, technology implementation, collaboration plan and business process workflows.
- **Operations management:** An operations management system provides two-way communication between the data generated on the plant floor and the software systems used by plant personnel to monitor the performance of one or more facilities. This extends to maintenance plans and delivery scheduling.
- **Alarm management:** IOC design requires operators to quickly respond to alerts and alarms from multiple facilities. To provide this capability, IOCs must use advanced tools to help operators filter and prioritize responses to alarms.
- **Situational awareness:** There are three steps to situational awareness (i.e., perception, comprehension and projection), and the outcome of this process is improved decision-making, quicker action and faster resolution of issues.
- **Software visualization and control:** Control room design—especially related to comfort, sightlines, acoustics, lighting, visibility, communication and ventilation—has a direct impact on operational effectiveness, and it should be executed in accordance with ISO 11064. By incorporating ergonomic elements into graphical human-machine interface and physical control room IOC design, decision-making quality and speed improve significantly.

Results in the oil and gas industry: Developing optimal collaboration and remote operation capabilities.

An oil refiner that had been executing the same manual processes across disparate departments for decades created an IOC that aligned with its goal to become more digitally driven. By partnering with the authors' company, the team updated critical OT and information technology (IT) at its plants and facilities by implementing an IOC with the latest technological advances for optimal collaboration and remote operation capabilities.

The IOC reduced shift handover and field operator time by implementing digital signatures, along with mobile critical information sharing to improve workflows. User-centric digital applications improved communication and decision-making among cross-disciplinary teams.

With the implementation of OT/IT integration from field devices to the control room, and by connecting the operations asset management system with the company's enterprise resource planning system, the refiner implemented 32 unified workflows incorporating more than 1,800

total users, including 400 field operators.

Through semi-autonomous machine implementation, the estimated production efficiency increased 2%–5%. Finally, the team deployed outcome-based project management initiatives with multiple system integrators and engineering, procurement and construction (EPC) partners for ongoing optimization projects.

Integrating a remote distributed control system environment. An LNG producer needed to quickly bring three new LNG trains online to increase its capacity. However, it faced a major obstacle because the ideal placement for these new trains was in an extremely isolated location, with frequent harsh weather conditions.

To address this challenge, the company consulted with experts at the authors' company to create an IOC. Together, they integrated a remote distributed control system environment with the entire upstream and downstream business chain—supporting business operations, planning and logistics teams.

All operations staff now work primarily at the IOC in a more desirable and much safer location. The new operation management and asset reliability management systems turns data into actionable information for critical operational processes, enabling predictive and targeted maintenance to reduce required operator rounds and visits to the site for maintenance.

The IOC helped this producer increase its LNG delivery capacity and meet contractual obligations by reducing unexpected incidents, while improving its asset integrity and organizational resilience. This improved long-term safety, and it used capital more efficiently through clearly defined operational workflows and connected business functionality.

IOC recap. To function effectively, IOCs require:

- Collaboration spaces and the appropriate mindset among cross-functional teams
- Modern automation and network infrastructure
- Automation and safety systems, end devices and instruments, and real-time data collection
- An information management plan
- OT/IT integration from field devices to the control room and throughout the organization
- A control room environment that supports semi-autonomous and autonomous operations, using advanced situational awareness tools (e.g., AR)
- Technology to turn data into actionable information and to execute predictive operations and maintenance
- Integrated security for remote access
- An organizational drive to reduce costs and improve performance.

By locating cross-disciplinary teams under one roof, process manufacturers can enhance efficiency and remain competitive because insight sharing grows among collocated teams. Moving operators away from manufacturing sites and hazardous environments improves personnel safety, making it easier to recruit and retain personnel.

An IOC is more than a physical workplace for a process manufacturer's staff. It represents a company's repositioning as a digital enterprise, staying at the forefront of new technology to optimize both operational and business process efficiency. An IOC provides an optimal environment to run advanced software solutions for operational, sales, inventory and supply chain management—thus helping process manufacturers maintain a technical and collaborative edge as they lead the way into the digital future. HP

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Reliability analysis of analyzers bridges the gap between assessing and addressing risk

For most refinery facility managers, the demands of running plants efficiently, meeting environmental regulations and maximizing returns on product specifications challenge even the most disciplined professionals. Managers whose schedules are consumed with urgent matters are challenged with finding time for proactive preventive maintenance, especially for necessary and mandated analyzers.

Despite their vital role in plant operations and protecting the health and safety of plant personnel, most analyzer systems do not receive the resources required. Decision-makers may be hesitant to make large-scale investments in the operations, maintenance and upgrades of analyzers. Poor (or no) business cases showing long-term returns on investment, or lack of defined risks connecting analyzer failure to the financial cost, are the underlying culprits.

Consequently, complex analyzer systems often run deep into obsolescence with multitudes of band-aid fixes and are only upgraded as a last resort. Projects are then executed with rushed schedules and shoestring budgets because they were never part of the master plan. Ironically, these installations cost the plant more money than if the system upgrade had been scheduled.

Reactive maintenance always costs more than proactive maintenance. Any plant manager can probably relate to the ever-present threat of being snake-bitten by an emergency analyzer upgrade project with limited options, high cost and high visibility, such as an emergency replacement of continuous emissions monitoring systems.

If your plant has numerous process and regulatory analyzers, there is a better way. Suppose decision-makers can be convinced of the value of an up-front effort to perform holistic surveys on analyzers and establish a long-term upgrade schedule. In that case, facility managers can reverse the cyclical pattern of putting out fires and begin to reap the long-term benefits of a carefully calibrated maintenance plan.

Developing a solid maintenance master plan can be challenging when competing for priority with smaller, less costly projects that can be considered quick wins. So, how can you effectively create a sustainable, long-term plan that pays dividends and keeps the plant analyzer systems out of the dreaded reactive maintenance cycle? Perform a holistic system survey, develop a master evergreen maintenance list, assign ownership early on and make sure to pitch projects by translating technical findings into financial terms leadership will understand.

Consider a holistic survey. Holistic surveys can be done on many systems, but the process becomes more complex for analyzers because of unique regulatory variables. For example, unlike electrical substations, the regulatory rules for analyzers change almost annually because they monitor and report emissions from the refinery. These emissions are highly scrutinized by regulatory bodies and the public, which may hurt the overall reputation and cause violations that impact regulatory decisions and environmental justice considerations.

Regulatory components strengthen the case for why a holistic survey is especially important for analyzers. If there is a failure and it is difficult to get parts, it directly impacts operations because safety and regulatory issues immediately rise to the top of the most urgent priority list for regulators. Stakeholders have no choice but to address compliance issues immediately, no matter the cost.

Consider a facility that has a failing critical emissions monitoring analyzer. Operational, financial and public-relations risks are high. If the analyzer is obsolete, spare parts are no longer available. In such a case, decision-makers must immediately spend whatever it costs to upgrade the analyzer, even if the project was not planned or budgeted. Sometimes, a short-term rental system is a viable option, but this can often turn into a long-term rental with costs quickly exceeding the costs of an upgraded system.

Beyond the bottom-line impacts of unbudgeted expenditures, organizations could face a public relations crisis and risk their relationship with governmental authorities because of faulty or absent regulatory equipment. While less critical equipment can be taken offline or bypassed during an upgrade or repair, this is not an option for a regulatory component. Regulatory bodies often require notification of analyzer malfunction with primacy, expedited costs/shipping considerations, extended downtime, etc. Additionally, the newly installed analyzer will require initial certification testing that will have to be contracted by third-party services that may not have the resources to support the project without significant unplanned cost.

In the cost-benefit analyses of holistic surveys vs. just-in-time crisis response, decision-makers must understand this will happen again, resulting in a cycle of focusing on the latest emer-

gency and never addressing the root causes. However, no plant manager will approve an expenditure of resources on a system study if it is not directly tied to an actionable plan.

Pitfall #1: Asking for a site survey without a defined action plan. Before asking for funds to hire experts to produce an expensive report, ensure the team understands what the data will be used for: to create a master, evergreen maintenance plan.

Evergreen lists provide managers with a tool to paint a holistic, realistic picture of upcoming analyzer projects for leaders to understand and assess in the budgeting cycle. Although the cost of developing and maintaining such a list can create sticker shock, translating analyzer failures into financial risk can justify the plan and make it easier to convince the leadership of its importance.

Analyzers are complex, with sophisticated sampling and calibration systems. Many are housed in their shelters in the field and have heating, ventilation and air-conditioning systems to keep the surrounding environment clean and stable. As a result, it can be time-consuming to get a complete picture of model numbers, obsolescence and parts availability. The picture gets complicated and costly if the systems reside in hazardous classified areas.

This is where a planning team can balance the insights of the facility manager's technical counterpart, who may want to go into more detail than necessary, with what is financially feasible to decision-makers. Managers should also factor in the ongoing maintenance of the list. Paying for a holistic study makes no sense if the resulting upgrade plan is not maintained long term.

Pitfall #2: Performing a survey without identifying a long-term owner. Once decision-makers agree to the initial study, assigning an internal expert responsible for maintaining the data ensures the initial investment. The person who will be responsible should also be involved in developing the evaluation plan. This step is crucial; without an assigned person committed to the concept, any money spent on this effort will be wasted.

An internal evergreen expert can be trained to manage the evergreen spreadsheet or database efficiently. The system is intuitive to whomever has helped create it, and the feeling of ownership from the development encourages that expert to be more invested in maintaining it.

The first step in building this internal skill set is to identify the primary internal content expert and ensure that person understands the project's goal and their role. The expert must see the evergreen list as a smart strategic investment.

For example, despite their extensive knowledge on the subject, maintenance and reliability personnel may not be ideal candidates for maintaining the evergreen list because they often deal with emergencies, which naturally interfere with long-term maintenance projects. Successfully creating and maintaining the evergreen list takes time and planning.

The task is well-suited to a project leader or engineer with the bandwidth and organizational skills to reliably manage and maintain the list. Field technicians who are in the plant or the field every day working on the analyzers and know their operational status can provide technical input.

The internal evergreen list expert must take the input provided by the technical and maintenance staff and drive the tasks, keeping staff on schedule, managing the budget and acting as the intermediary to translate technical language into dollars-and-cents proposals that can be understood and accepted by leadership. Typically, these efforts fail because the technical needs are not converted into financial costs and risks. In addition to maintenance plans for monitoring equipment and analyzers, upgrades and ongoing support to data acquisition systems must be included to maintain streamlined compliance reporting and data reviews.

Pitfall #3: Failing to translate and quantify risk into financial terms. Familiarity with the reliability of analyzers is valuable to decision-makers for safety and regulatory reasons and for the general planning of maintenance and replacement.

Reliability—or the absence of it, in the form of equipment failure—is one piece of the risk analysis puzzle. Risk is a combination of the likelihood that a failure will occur, along with the consequences of that failure. Many technicians and maintenance engineers excel at describing scenarios and predicting the likelihood, but they may need help balancing that information against other competing interests to determine where that risk fits in terms of priority for capital expenditure.

That balance is a key part of any meaningful discussion with leaders about what deserves budgetary priority. In many cases, the underlying issue is an inability to convey what is most important (e.g., breakdowns, equipment failures and the inability to make repairs because of obsolescence). Technicians and planning professionals must take this a step further and balance the identified risk against the cost and the effort that will be required to mitigate that risk.

Experts with a technical background know these things are important, but they often struggle to communicate them using the language of risk analysis that will resonate with decision-makers. An experienced project leader or engineer brings the skills to translate such vital analysis.

Consider the scenario where an analyzer is old and will break down. A leader may ask what the risk would be if it fails. The risk may be fines to the organization from regulatory agencies when a boiler is forced to be taken offline because an analyzer breakdown inhibits emissions monitoring.

This is an accurate description of the consequences of an analyzer failing. However, risk analysis is a multi-faceted examination of consequences and likelihood of failure in concert. A project team expert can ask the right questions to understand the entire risk spectrum—the likelihood and how to plan for it.

A holistic survey helps organizations go beyond planning for failure. For example, a particular analyzer is obsolete, which means spare parts are hard to procure, but the facility has one set of spare parts on hand. On average, spare parts are needed about once a year, but that has been increasing. In the subsequent 5 yr, it is reasonable to expect one failure will use the spare parts, and a second failure will result in a shutdown. In this case, the internal expert can forecast a high chance of being out of commission within 2 yr–3 yr and certainly within the next 5 yr.

Equipped with a reasonable time frame, a facility manager can make a plan that balances the consequences with the likelihood the analyzer will reach the end of its lifecycle by a specific date. The manager can then determine an acceptable level of risk and isolate the point at which that risk becomes unacceptable, enabling the organization to set priorities. This contrasts

with operating in crisis mode, which demands addressing whatever emergency is most pressing at a given time.

Finally, with the likelihood and consequences defined and quantified, the last step is translating that data into financials. Consequences like regulatory fines and/or lost opportunities during shutdowns can be translated into monetary costs. Talk with key plant stakeholders to help define those costs so managers do not need to. Get an accurate estimate of the project's total costs to replace the analyzer system. Additionally, always be prepared to give a cost for the do-nothing option, such as short maintenance outages and costly spare parts. Armed with the risk (likelihood and consequences) quantified into financial terms, you are ready to present a strong case to management to replace those problematic systems. Remember, the goal is not necessarily to win project approval but to provide leaders with as accurate a picture as possible and a defined plan. Sometimes, the correct answer is to accept the risk for a time. Do not become so invested in the project proposal that you lose sight of the overall facility.

With this template, return to the evergreen list model. After compiling the data analysis into a compelling case to replace a system, apply the principles of holistic planning in the appropriate level of detail to all the analyzer systems on your evergreen list.

Pitfall #4: Drowned in detail. Performing the in-depth analysis as outlined for every analyzer in the plant could range from daunting to despair-inducing. Do not drop the ball at this point! Prioritize your systems and give complete treatment only to those that need a thorough evaluation. For systems that are in good shape, use your best judgment. Define the framework for the risks and costs, but if risks are low, provide a rough order of magnitude estimate. The list should be ordered from immediate to long-term needs. Ideally, each upgraded system should move to the bottom of the list as it is addressed. The data collected to identify risk scenarios and costs move with the items on the list and will only need review and updates in the future. At this point, the hard work is done, and what is left is a maintainable, long-term action plan that can readily convey the status and risk of any analyzer in your plant.

With a dedicated analyzer maintenance plan or a group devoted to managing such plans, plants that utilize key performance indicators (KPIs) to communicate performance and reliability will have better data. It is to be expected that KPIs that track downtime will most likely increase (or perform lower) in the short term. However, the long-term health of the plant's analyzer programs will increase and should begin to improve, and that improvement will be reflected in the KPIs for the program. HP

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Implement advanced level control techniques to improve crude distillation unit stabilizer performance

The performance of refinery operations depends on the stable operation of the plant. The primary crude distillation unit (CDU) generates a lighter component from its overhead and processes it into a stabilizer to separate liquified petroleum gas (LPG) and naphtha components. Therefore, any operational improvement leads to improved refinery margins by improving the product quality and optimizing the reboiler heat duty.

The capacity of a particular CDU was 18 MMtpy, and it processes different types of crude with sulfur levels of 1 wt%–3 wt%. The production of LPG and naphtha varies depending on the type of crude processed. The overhead vapor from the CDU is cooled and routed to the overhead receiver vessel. However, the condensed liquid from the overhead vessel is partly routed to the column top as a reflux to maintain the temperature, and the balance liquid is sent to the re-contacting column to feed the stabilizer.

The overhead gases (e.g., uncondensed material from the overhead vessel top) were routed through a two-stage wet gas compressor, where the gases were pressurized up to 9.0 kg/cm^2–9.5 kg/cm^2; after cooling, the overhead gases were routed to the re-contacting column. Some parts of saturated gases from other units, such as vacuum gasoil (VGO) and diesel hydrotreating (DHDT) units, were also routed to the re-contacting column along with the compressed gas. Finally, the liquid hydrocarbon from the re-contacting vessel bottom was routed to a stabilizer for the separation of naphtha and LPG. The main feed to the stabilizer was from the CDU overhead via the re-contacting column based on the vessel level control in level flow cascade mode.

The stabilizer consists of a column, an overhead vessel and a reboiler at the bottom to maintain the stabilizer's bottom temperature. Parts of the cooled liquid were routed to the column top as a reflux to maintain the top temperature. The balanced cooled product (e.g., LPG from the stabilizer-overhead vessel) was routed to an amine column for the removal of hydrogen sulfide (H_2S) before sending it to the downstream unit to remove mercaptan.

The stabilizer bottom product stabilized naphtha, which is then routed to the naphtha hydrotreater (NHT) unit for further processing. A level indication was provided with a control valve in the rundown line to maintain a steady level in the overhead vessel and column bottom. Unstabilized naphtha generated from diesel hydrodesulfurization (DHDS), DHDT and VGO mild hydrocracking (MHC) was also directed to the stabilizer feed pump suction to get processed in the CDU stabilizer.

Typically in refineries, advanced process control (APC) is implemented for stabilizer operation, product yield and quality optimization; however, due to continuous disturbance in its operation, APC was not implemented in this stabilizer. Another reason for not implementing APC is because unit operations were more than the design capacity, resulting in fewer margins in operating parameters such as reflux flows, limitations in gas compressors and cooling systems.

Problems. The CDU stabilizer performance was unsatisfactory and was operating with a significant amount of disruption, such as a disturbance in LPG quality (mainly LPG weathering), amine carryover with LPG and hydrocarbon carryover with an amine. An additional knock-out drum (KOD) was provided after amine treatment to arrest the amine

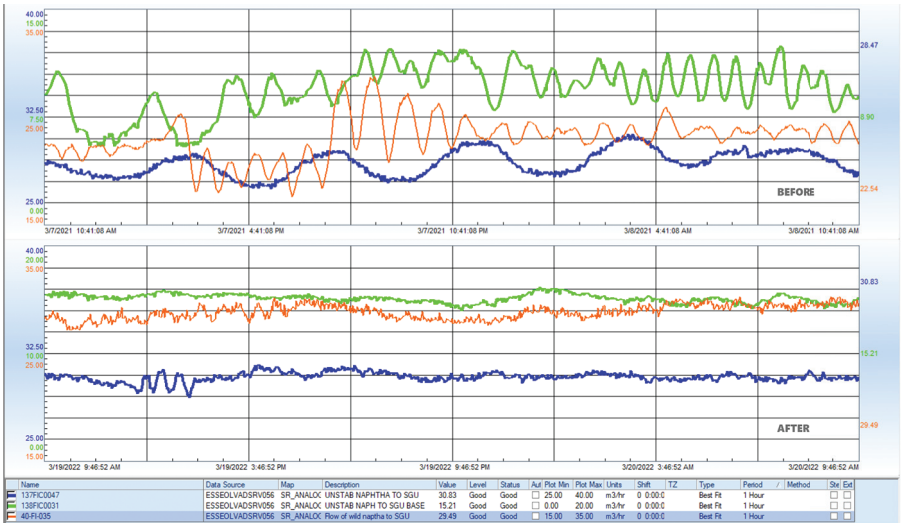

FIG. 1. The feed flow trend from DHDS, DHDT and VGO MHC units.

carryover with LPG. The LPG rundown flow control was not working smoothly in auto cascade mode, so some was kept in manual control mode for less flow variation.

Improving the operation of stabilizers increases profit margins by reducing product quality giveaways. TON control is an ideal tool for achieving maximum improvement in stabilizer performance. TON control is also beneficial for any level of control for steady flow to the downstream section.

Analysis of feed to the stabilizer. The incoming stream flow was set for 24 hr of operation, and the product outgoing stream flow was critically analyzed to identify the problems and improve the stabilizer performance feed.

Approximately 80%–85% of the CDU stabilizer feed was from CDU overhead and unestablished naphtha, and about 15%–20% of total feed was from other units like wild naphtha from DHDS, DHDT and VGO MHC stripper. Wild naphtha flow from DHDS, DHDT and unstabilized naphtha flow from VGO were analyzed (upper half of FIG. 1).

Primarily, the CDU, overhead naphtha (80%–85%) and compressed unsaturated gas were routed to the re-contacting column from the main CDU fractionator and the subsequent column bottom was routed to the stabilizer as feed. The feed flow from the CDU overhead and the re-contacting column was critically analyzed, and a wide flow variation was noticed for the CDU overhead liquid flow (upper half of FIG. 2).

Wild and unstabilized naphtha from DHDT, DHDS and VGO MHC flow variation was continuous, causing trouble in stabilizer operation. Feed coming to the re-contracting column from the CDU overhead was a wide flow variation with continuous disturbances.

In the crude unit, blend changeover is a common requirement and is done every 2 d–3 d. It is also observed that higher levels of disturbance occur during this blend changeover. The disturbance from re-contacting the column to the stabilizer was less than the CDU overhead feed flow.

Analysis of product flow from the stabilizer. The rundown product from the stabilizer bottom and overhead vessel with the downstream LPG, an amine extraction column and LPG KOD level were analyzed critically with the flow.

The stabilizer bottom level and flow were stable with a marginal variation. However, the overhead vessel LPG level and flow variation were wide, resulting in amine carryover with LPG (upper half of FIG. 3).

Implementation of target opening nonlinear (TON) control. The feed and product flow fluctuations were marginally higher in the normal distributed control system (DCS), as stated above in the flow trends. It was decided to implement TON control for performance improvements of selected level control where flow deviation was on the extreme side, such as the stripper overhead in the DHDS and VGO MHC units and the stabilizer overhead in the DHDT unit for a reduction in wild naphtha and unstabilized flow variation. TON control was also considered for the CDU overhead flow to the re-contacting column level and stabilizer overhead level control to reduce flow variation.

TON control is a correlation-based control that works based on the level difference, set level and actual level. The correlation used for level control is (Eq. 1):

$$CV_{OP} = (L_A - L_S) \times M + T_{OP} \qquad (1)$$

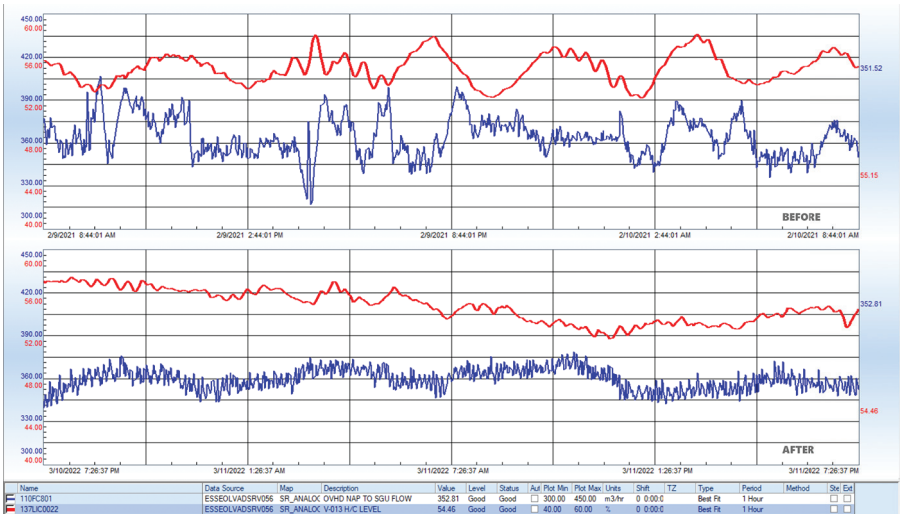

FIG. 2. The level and feed flow from the CDU overhead trends.

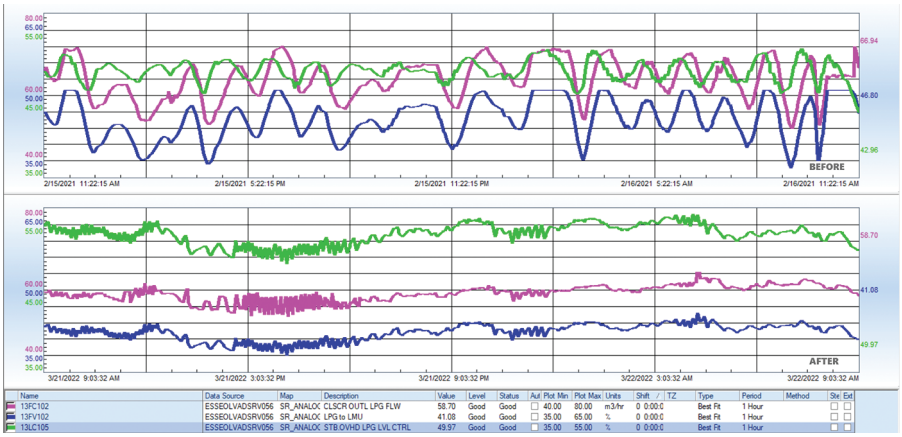

FIG. 3. The stabilizer overhead vessel product flow, level and control valve opening trends.

The calculated control valve output to the respective flow control valve (CV_{OP}) = actual level (L_A) – set level (L_S) × M + target output (T_{OP}). The control configuration can be selected as: 1) for normal DCS mode or 2) for TON control mode.

This modification can be carried out in the DCS with the help of an instrument engineer. Apart from the selection of DCS or TON, three fields exist in DCS: target output, level set point and factor M. Target output is the flow control valve's average opening; the level set point is the desired level to be maintained (actual level indication value will be taken from DCS); and M is a factor to be set once as per operating practice and flow variation with a level that is very similar to controller gain—usually, it will vary from 1–2.5.

Benefits. After implementation of TON control in the above levels, the flow variation was found to be significantly less than the DCS. With this reduction in flow variation, the performance of the stabilizer was found to be stable, and the product quality concerning LPG weathering was steady. Due to a steady LPG flow after the implementation of TON control, the amine carryover problem with the LPG was eliminated. Flow trend from DHDS, DHDT and VGO wild and unstabilized naphtha coming to the stabilizer after TON control is shown in the lower half of **FIG. 1.** The level and flow trend for the CDU overhead coming to the re-contacting column is shown in the lower half of **FIG. 2.** The level, flow and control valve opening trend for the stabilizer overhead going to the amine extraction column is shown in the bottom half of **FIG. 3.**

Additional level TON control was implemented, such as a re-contacting column, stabilizer bottom level and amine KOD to further the improvement of the saturated gas unit.

Takeaway. A CDU's stabilizer is a critical section of any refinery. The steady unit performance will reduce product quality giveaway and increase profitability. The steady LPG flow to the downsteam amine section will eliminate amine carryover along with LPG product. TON control has been implemented in DHDS, DHDT and the VGO MHC stripper and stabilizer overhead section, the CDU overhead, re-contacting column bottom, stabilizer overhead and bottom level control at the author's company. HP

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Leading capital projects in a VUCA environment

A convergence of events has disrupted the construction industry. Leaders of firms are responsible for decisions that impact their capital projects. Increasingly, these decisions are made in a world that is volatile, uncertain, complex and ambiguous (VUCA). While these conditions can complicate decision-making, embracing collaborative, creative communication and a flexible approach will reduce risks and result in more predictable project outcomes (FIG. 1).

Based on the leadership theories of authors Warren Bennis and Burt Nanus, the term VUCA was first used in 1987. Later, it was embraced by the U.S. Army War College to describe the military challenges in a post-Soviet era. Military leaders no longer had a single enemy upon which to focus but faced a multitude of threats that required different ways of thinking, seeing and reacting.

VUCA describes the situation of constant, unpredictable change that is indicative of the environment in construction today. Rising material costs, supply chain interruptions, labor shortages and political, economic and regulatory uncertainty are just a few of the factors impacting capital projects. The current environment demands project planners and managers avoid traditional approaches to management and project delivery. Whether a project is grassroots, expansion or retrofit, owners, engineers and contractors must work in concert to address the issues and challenges facing capital projects.

Traditional design-bid-build project delivery, in which the design team makes all decisions and then sends a project to bid, purposefully keeps teams and tasks siloed to limit liability. Newer project delivery methods, such as design-build, early contractor involvement (ECI) and advanced work packaging (AWP), seek to bring teams together more collaboratively. These methods achieve the most success if collaboration happens early, is guided by a formal preconstruction process and has full buy-in from all participants. Early planning and tracking allow collaborative activities to create a feedback loop to proactively refine a project's schedule and cost rather than letting problems snowball (FIG. 2).

ECI, while closely related to design-build project delivery, brings subcontractors to the table even earlier in the process—at the design concept or schematic phase. By tapping the expertise of subcontractors, the team can utilize their unique perspectives, ideas and solutions regarding constructability. This is especially critical in the current environment, where supply chain problems make it imperative to consider more alternatives than usual when it comes to project design, material selection, and fabrication and shipping choices. For example, for many steel installations, lower weights through the use of more pieces is preferred to reduce steel material costs. In a VUCA world, however, where limited availability of skilled labor is increasingly an issue, heavy

FIG. 1. Preconstruction support of phased procurement allows for modularization and just-in-time receipt of equipment modules.

FIG. 2. Clash detection and structural connection optimization are additional benefits of contractor involvement during preconstruction. These efforts generate reduced field labor costs and more certain project success.

weights with fewer pieces reduce fabrication time and field labor. For piping installations that are typically welded with random ends to accommodate flexibility in the field, they are now maximized for shop fabrication with exact fit bolt-ups to reduce field installation time (FIG. 3).

Rising material costs, supply chain interruptions, labor shortages and political, economic and regulatory uncertainty are just a few of the factors impacting capital projects.

Contractors and subcontractors often provide the most direct connection to suppliers and can alert the team if delays or fabrication difficulties are imminent. They may have longstanding, trusted relationships with suppliers, enabling them to secure holds on prices or other benefits that would otherwise be unobtainable. Their knowledge can add value when sequencing project activities—a particular asset in times of a VUCA environment. For petrochemical and oil and gas facilities, inefficiencies can occur when procuring and coordinating shipment and storage of key components, including tanks, pipes and vessels. ECI facilitates contractor-engineer communications that break the typical long and circular shop drawing cycles and replace them with joint working reviews with the fabricator, shortening the time to fabrication to take advantage of securing shop time earlier and with cost certainty. Onboarding sophisticated contractors or specialized subcontractors to support a project team using sophisticated pre- or macro-planning measures such as building information modeling can not only optimize project sequencing to reduce bottlenecks, but can maximize transport loads to reduce costs and the possibility of material interruptions in the field. A related concern that has cropped up during pandemic-related supply chain disruptions is client-led procurement that does not dovetail well with the overall project schedule. Having a coordinated preconstruction team, in which a responsibility or accountability for procurement is streamlined, is crucial (FIG. 4).

FIG. 3. Integrity projects often involve bringing once underground process lines above ground. Early planning with the contractor enables the planning, modularization and permitting to work in urban spaces safely and efficiently while managing costs and schedule.

FIG. 4. Reducing impacts to an operating facility is paramount to company returns. Initiating discussions early between the unit operators and contractor provides an opportunity to create a schedule flexible to the needs of all stakeholders.

Costs associated with bringing contractors on as consultants early in project planning are typically offset by the advantages of ECI. This is especially true under VUCA circumstances. Getting involved early gives subcontracting companies confidence in their approach to the project, resulting in lower contingencies and more competitive pricing. Faster permitting, better regulatory compliance and fewer change orders—by orders of magnitude—are also associated with ECI. Contractual language that clarifies how the risk of price escalation will be shared is another factor that gives all stakeholders confidence—additionally, it can improve bid numbers by reducing uncertainty.

Getting the team on board.

The construction industry continues to struggle with the level of competitiveness that has been built into contracts and project delivery methods for so long. In a VUCA world, adversarial relationships cause greater inefficiencies than ever: teams need to move from an attitude of seeing "problems" and "solutions" to one that considers "issues" and "accommodations." Problems are handled in reactive ways, whereas what is needed on today's jobsite is proactive analysis and planning. In part, this is a matter of timing and of formalizing processes. Soft skills and a collaborative attitude on the part of individual team members make a big difference. At all levels of each organization involved, team members must have a sense of shared interest in project outcomes. They need to fully understand their roles and responsibilities, including how their tasks relate to overall project goals. When conducting training programs—or individual mentorships—it is important to convey appreciation for the viewpoint of all stakeholders involved. Trainers and mentors should provide members of their project team with overt permission to consider different perspectives. Doing so will ensure that, as a project progresses, adversarial or defensive positioning can give way to understanding and accommodation.

The key to leading capital projects in a VUCA world can be summed up as a mindset. Problems generally arise from poor or late planning. Having ample time to deal with problems—whether the delivery of materials, a workforce shortage, slowdowns attributable to the regulatory process or any other common contemporary issue—puts decision-makers at ease and improves their problem-solving abilities. Having ample time can feel like a luxury, but to accomplish on-time, on-budget projects, it is increasingly necessary and something that can be achieved if the planning is a collaboration vs. a hand-off. HP

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Trip your turbine troubles: Optimize the reliability of steam-driven turbines

Steam turbines are essential for successful operations in refining and petrochemical plants, such as at the wet gas compressor and regenerator air blower of a fluidized catalytic cracking unit (FCCU). However, other smaller turbines can also perform critical functions that are important to the overall operation of production units. Much focus is commonly given to the main production process itself; as a result, turbine reliability improvement considerations may be secondary—that is, until severe damage occurs, sometimes causing manufacturing shutdowns for weeks on end.

As one example, severe turbine issues in a medium-size refinery shut down both the FCC and hydrogenation and catalytic cracking (HCC) units for more than 5 wk, resulting in production losses exceeding $65 MM. Such incidents can be mitigated by optimizing the steam quality that drives turbines. This requires designing effective condensate drainage from both the supply lines and respective turbine installations, as well as disentraining wetness from the steam flow to mitigate against erosion, precipitate and slug damage.

Following the delivery of high-quality steam, turbines must also be adequately drained of condensate to help prevent trips during startup, corrosion during idle periods, condensate accumulation during operation, and hydraulic shock to downstream steam lines or equipment. Condensate removal also helps reduce precipitate buildup.

Optimizing the steam system quality begins with proper design of the main utility headers. This requires effective collecting leg design, proper selection, placement and maintenance of condensate discharge locations (CDLs)—including the steam traps and valves—and installing high-efficiency moisture separators upstream of steam turbines. Although most of the steam trapping requirements are relatively simple, load calculations should be done to properly size the traps used to drain condensate from any inlet separator used and from the exhaust side of back pressure or vacuum turbines relative to the potential higher load from steam wetness and condensation. Although not a common consideration, the condensate loads at both the separator and the turbine exhaust side can be substantial.

When properly designed and installed, a high-quality steam supply helps optimize turbine efficiency and reduce reliability issues associated with blade erosion, plating, turbine trips and severe damage from hydraulic shock.

Vacuum/condensing turbine installations require additional design considerations relative to the steam quality supplied to the ejectors. Improvements to steam quality can be achieved by incorpo-

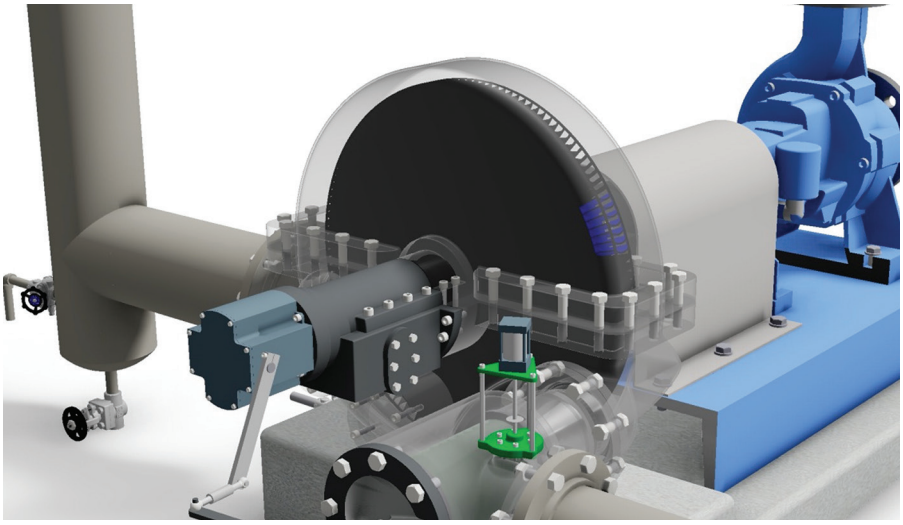

FIG. 1. Even simple, single-stage turbines are sophisticated equipment requiring appropriate care.

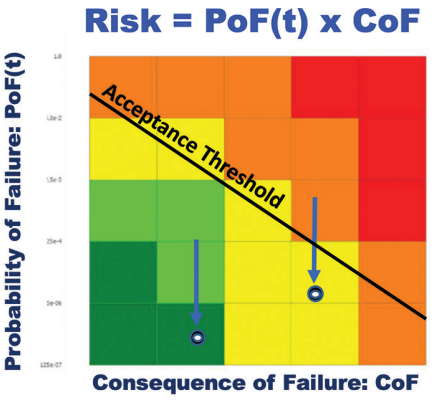

FIG. 2. Lowering risk requires reducing the probability of failure (PoF) for an equipment asset. In the case of turbines, this can correlate to lowering the probability of failure caused by condensate.

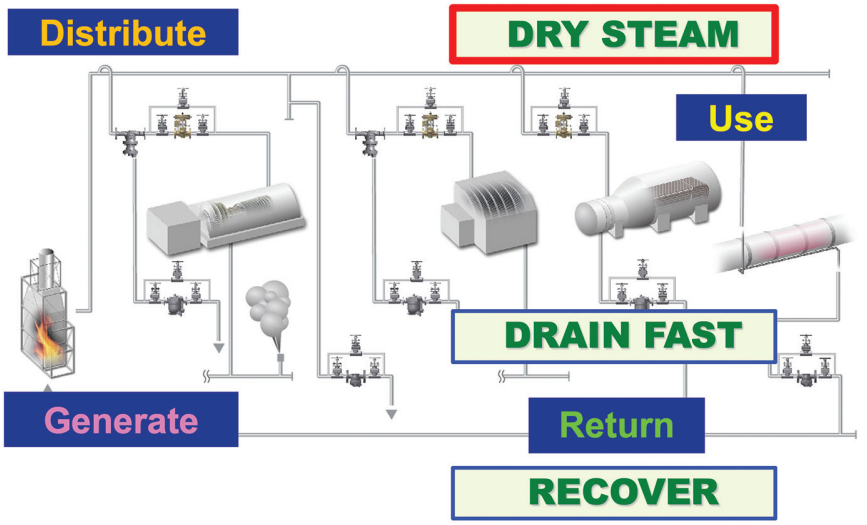

FIG. 3. Dry steam cannot be distributed in a steam system. Steam is either superheated or wet.

FIG. 4. If not superheated, steam contains substantial moisture that should be disentrained and drained.

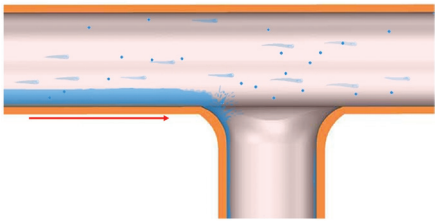

FIG. 5. All steam systems can have condensate flowing along the bottom of the pipe, and moisture is expected in flowing wet steam supply.

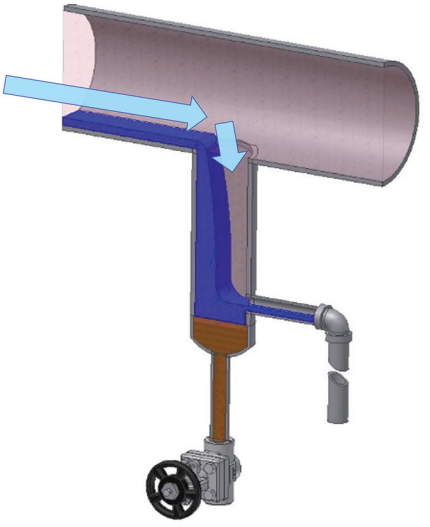

FIG. 6. A collecting leg must be adequately sized for high-velocity condensate to drain into it.

rating best practice design recommendations to help reduce ejector nozzle/throat erosion and precipitate buildup. These actions can help optimize and sustain benchmark vacuum pressures and surface condenser operation for longer periods.

Properly draining pedestal-mounted vacuum steam turbines can be especially challenging, as pumping (rather than trapping) systems may be required to remove condensate from the sub-atmospheric turbine case and exhaust piping. If drainage is inadequate, significant damage to internal turbine components, as well as a reduction in performance of downstream surface condensers, may occur. Each of these elements are reviewed in detail in the following sections.

Reducing risk. Steam turbines, even small ones, are sophisticated pieces of equipment (FIG. 1). It is common that turbines are the unnoticed, unsung heroes of the plant, functioning properly for extremely long periods of time—in a sense, forgotten until there is damage that can result in significant maintenance cost and service or production interruptions.

Due to concerns of production interruptions from downtime, many steam turbine areas can look like a fog zone, which is the result of multiple open steam bleeders as an attempt to prevent damage or imbalance. Even in such instances, turbines can experience incidents because the systems are either improperly designed or inadequately maintained.

One professional method to mitigate risk is to follow the principles of API RP 580/581.[1,2] FIG. 2 shows a typical risk mitigation matrix. Risk is the product of the probability of a failure event multiplied by the consequence of the event (typically in monetary terms). While the consequence of an event usually cannot be lessened without a change in design, multiple actions can be taken to reduce the probability of failure. This article provides focus on some of the possible mitigation designs that can help reduce the probability of failure relative to the steam system, water entrainment in steam, and condensate removal.

Notice the blue arrows in the matrix shown in FIG. 2 representing the reduction of risk deeper into an acceptance zone for two assets (such as turbines). It is recommended and possible to incorporate risk mitigation practices for all turbines in a plant, as well as other critical pieces of equipment, which lowers the combined risk of unwanted events.

Steam quality. Steam that drives the turbines can be either superheated, near saturation or wet. It is important to have steam without wetness as the drive source, and this is often the reason superheated steam is often selected for the design (FIG. 3).

There is a common misconception that plant steam is either superheated or saturated, but this is inaccurate because dry saturated steam cannot be sustained in a plant's steam system.[3] Boiler steam has significant wetness if not passed through a superheater, and usually much more wetness if generated from a waste heat boiler (FIG. 4). Steam quality without wetness is so important to turbine reliability that systems that are not supplied with superheated steam are recommended to have a best practice steam trapping design just before the turbine entry point, in addition to a steam separator and drain combination between that trapping location and the turbine entry point.

The need for adequate drainage and separation can be seen by examining FIG. 5. Disentrained condensate flows along the bottom of the steam system piping and some water remains entrained in the steam flow for wet steam systems. A first stage of removal can be accomplished by installing a properly designed collecting leg for condensate capture (FIG. 6).

Capturing and discharging condensate. Consider that steam's design pipe velocity is commonly at or above 90 mph.[4] A key requirement is to remove the condensate flowing along the bottom of the pipeline that has already been disentrained from the vapor. If not removed, it can form dangerous slugs—many case histories of significant plant shutdowns due to the resulting damage caused are documented (FIG. 7). The velocity of steam under constant load requirement conditions elevates dramatically as the available non-liquid-filled portion of the pipe decreases, escalating the propulsion given to the slug to create turbine destruction (FIG. 8).

Slug buildup can be mitigated by the installation and sustained maintenance of well-designed condensate collecting legs and steam trap stations, also known as CDLs (FIGS. 9 and 10).[4] Turbine reliability begins with well-maintained utility lines.

Another key improvement is to install an engineered separator and drain after an appropriate CDL and before entry into the turbine to disentrain a substantial amount of wetness that may be carried in the steam flow. This not only helps prevent erosion of the turbine blades, but also mitigates precipitate buildup. Examples are shown later in this article.

It is common to see a fog zone around turbines in many plants, the result of open steam bleeders with the intention to mitigate damage from condensate slugs (FIG. 11). Regardless, this practice often does not preclude incidents and proper CDL design and sustained maintenance are recommended.

Superheat. A misconception persists regarding superheat systems: that because the steam is superheated, adequate

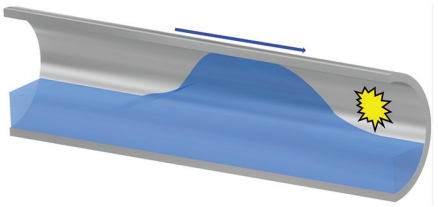

FIG. 7. As a slug's mass builds and closes off the pipe's cross-section, its velocity can rapidly accelerate.

FIG. 8. The potential damaged caused by slug-induced water hammer should not be underestimated.

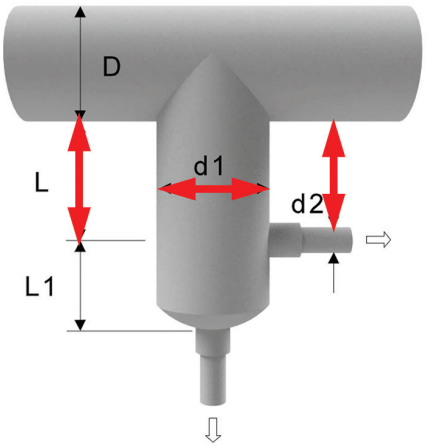

FIG. 9. A properly designed collecting leg requires adequate diameter, depth and distance before the trap take-off.

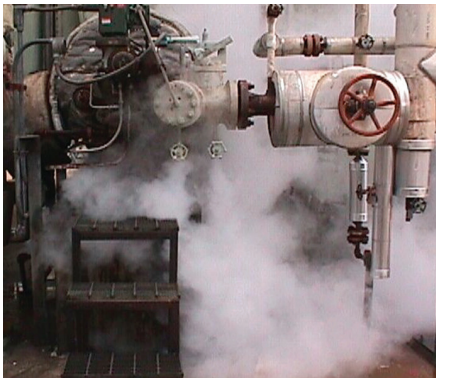

FIG. 11. Fog zones can create visual hazards and still be ineffective to mitigate turbine damage.

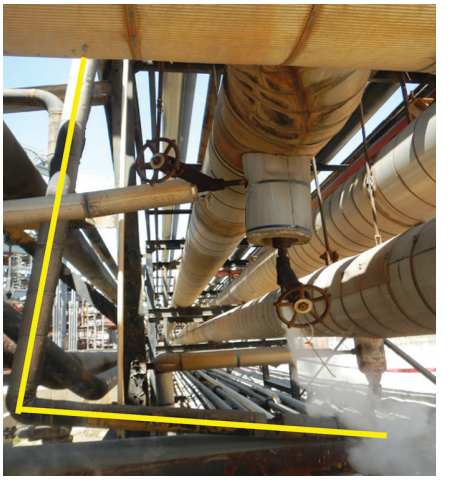

FIG. 12. This 24-in., 220-psig superheated steam line had a 400-ft section moved 7 ft by slug hammer.

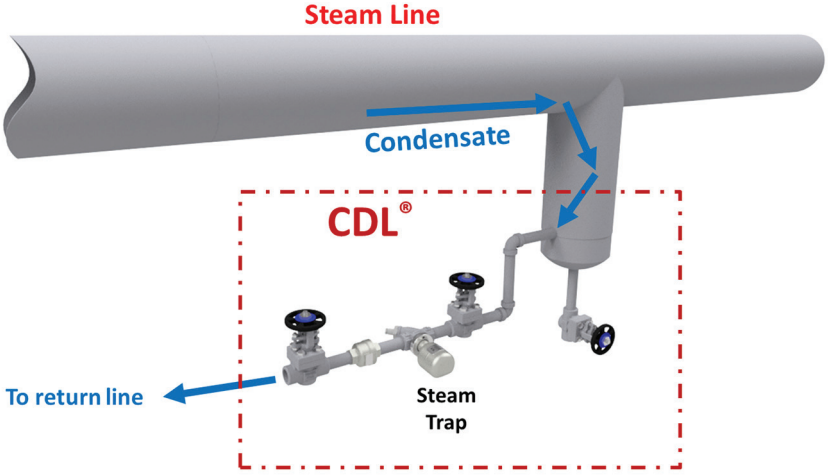

FIG. 10. CDL refers to the entire pipe assembly used to drain condensate, including the steam trap, piping and all valves.

CDLs are unnecessary. FIG. 12 shows a result in systems that are not adequately trapped. Water hammer from a slug of condensate moved a 400-ft. section of this 24-in., 220-psig superheated line a distance of 7 ft. When the drain valves were later opened, condensate drained continuously for 3 d.[5] The moral of this case history is that superheated mains can carry a lot of condensate and require well-maintained CDLs.

Turbine drainage. After utility lines are confirmed to have best-practice trapping and moisture separator installations, it is useful to examine at least seven areas on a turbine installation, starting with the inlet separator and continuing with multiple important stages through the turbine and its exhaust (FIG. 13).[6]

The CDL before the separator is intended to remove condensate that has already been disentrained. Each stage of the turbine installation can pool condensate and appropriate CDLs can mitigate issues.

FIG. 14 provides additional detail on the inlet side of a turbine installation. The trap on the separator is commonly larger than a standard utility main drip trap or the trap at the inlet of the control valve due to anticipated wetness to be removed, while the inlet to the control valve steam trap is typically a smaller size.

It is common to see inadequate drainage at the steam chest, trip and throttle valve, and even the casing drains. Often, these drains are plugged, which can lead to condensate buildup that causes damage. For these reasons, those connections are recommended for steam trap drainage (FIG. 15).

The supply steam quality and work efficiency of the turbine determine the amount of condensate on the exhaust side. Often, the trap for the turbine exhaust is larger than a simple utility main drip trap due to the potential for wet exhaust flow (FIG. 16).

Another misconception about steam trapping on turbines is that any type of trap can be used. However, many types of traps, such as inverted bucket, bimetal or expansion or balanced pressure thermostatics, and thermodynamic, have cyclical discharge characteristics, meaning they can back up condensate into the turbine, which is undesirable. Some traps, such as bimetal or expansion designs, can have large temperature suppression, draining condensate on cold startup but not draining effectively during normal operation. For this reason, it is preferred to use immediate response float trap designs (FIG. 17).[6,7]

Steam trap condition health is sometimes not carefully managed, and this can have a significant effect on turbines and other equipment, such as ejectors on air exhauster systems (reviewed later in this article). A blocked trap causes condensate backup into the separator it needs to drain and can render it useless, which highlights the need for effective, sustainable trap testing and maintenance (FIG. 18).[8]

Condensing turbines. Some turbines are designed to have their steam fully condensed by a surface condenser to create a vacuum or to generate optimum power. One such example is a condens-

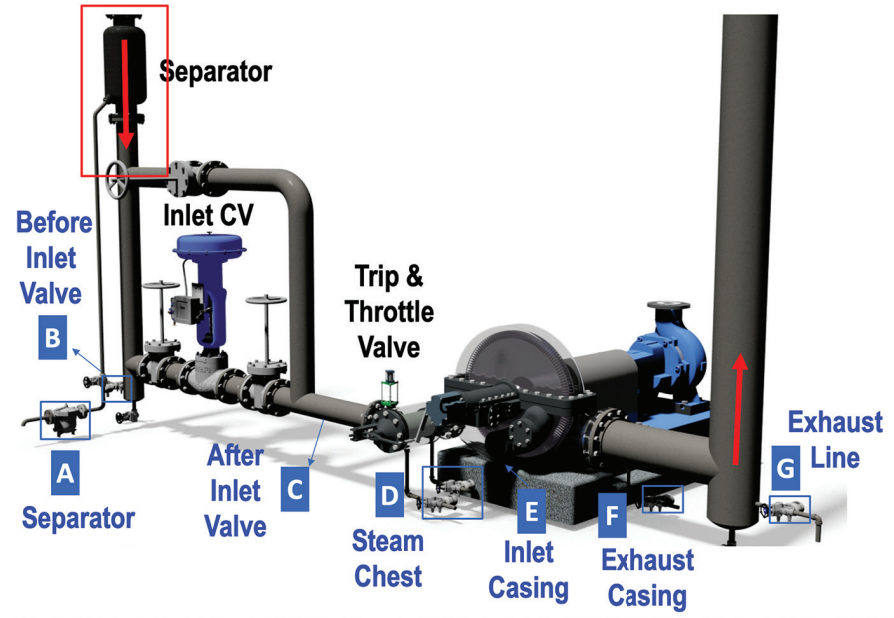

FIG. 13. Installing effective CDL at these seven drainage points can be crucial to improving turbine reliability.

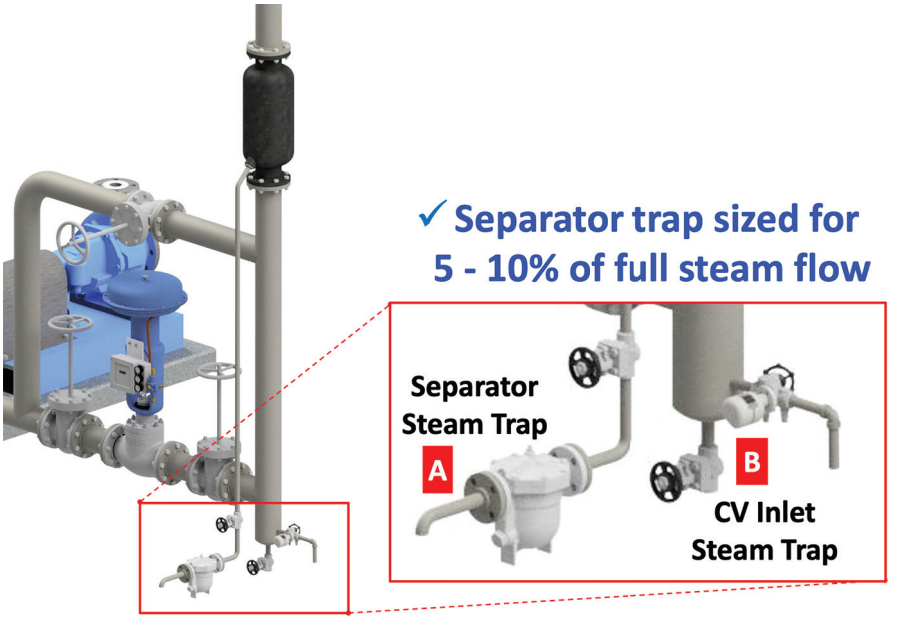

FIG. 14. The turbine inlet piping is the last defense to provide high-quality drive steam to the turbine.

ing turbine driving a gas compressor. Those turbines mounted directly on top of a condenser typically do not experience issues with condensate removal from the turbine casing. However, turbines mounted on a pedestal that exhaust steam upward to the condenser can experience significant difficulties in getting proper condensate drainage from the turbine casing.

Consider the desired discharge of condensate from a turbine casing through a steam trap to atmosphere. Depending on the elevation of the turbine over the trap and because the turbine drain/trap inlet is at vacuum, approximately 35 ft of head is needed to discharge to atmosphere. Typically, this is not available and, therefore, the system cannot drain (FIG. 19).[6]

An alternative might be to discharge the casing drain condensate to the hotwell, but unless the condensate can drain down by gravity, this system cannot work. Condensate will try to flood the turbine casing by manometer effect up until the horizontal entry level into the hotwell. However, it is likely that the water is spun by the turbine blade itself before this higher condensate level is reached. This can cause damage, loss of power, erosion and precipitate buildup issues (FIG. 20).

Since the turbine casing is in vacuum, a pumping method is needed where condensate gravity drains down into the pump's reservoir to be pumped into the hotwell (FIG. 21).

Air removal and steam ejectors.

Condenser systems condense steam, but not non-condensable vapors such as air. As a result, an air exhauster/removal system is needed. FIG. 22 shows basic details of such a system, incorporating first- and second-stage ejectors as well as a hogger jet system for large volume air removal on startup.

Steam ejectors are critical to create the necessary suction to pull air from the condenser, but the resulting mixture contains both some of the motive steam and air in the entrained flow. The multiple stages of the exhauster system are designed to condense that motive steam as it passes through, and eventually enable the air to be vented to atmosphere at the end of the second stage in the example shown in FIG. 22.

A condenser system can be expected to have significant amounts of air present on startup, so an additional "hogger" jet is often used initially to pull substantial amounts of air out of the condenser and exhaust it. Hogger systems do not have additional condensers, so a lot of steam can also be exhausted. For this reason, hogger systems should only be used on startup, but many are commonly used during normal operation to supplement the rest of a deficient suction system.

A hogger used in normal operation typically indicates that the main air exhauster system is not pulling enough air out of the condenser and the hogger is used to compensate. In many cases of proper ejector sizing, it indicates that the ejector nozzles and/or throats may have become enlarged due to erosion, and this can be an indication of poor steam supply to the ejectors. There may also be a precipitate buildup on the diffuser that further weakens the suction produced.

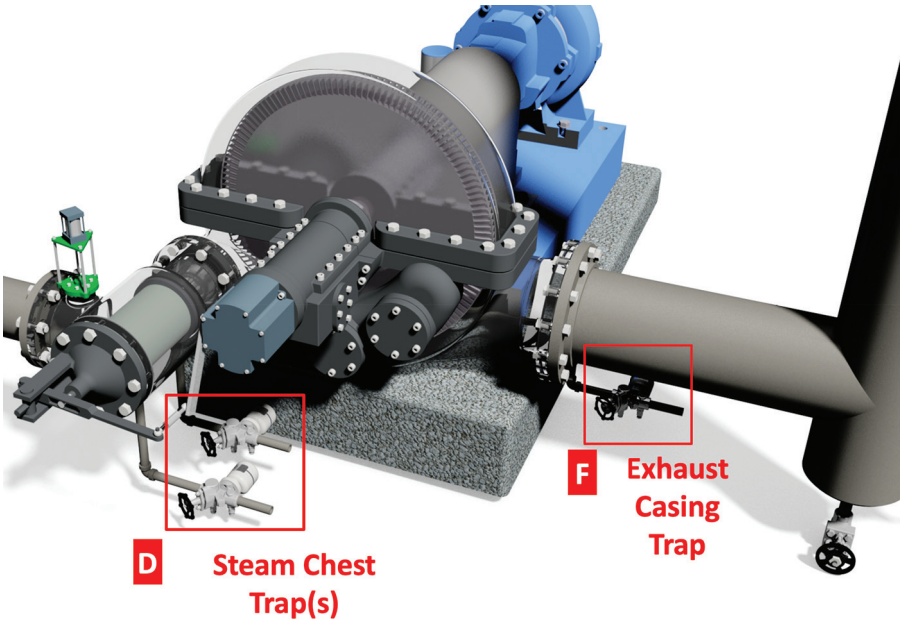

FIG. 15. Once steam enters the turbine, condensate can pool from work and radiation, and must be drained.

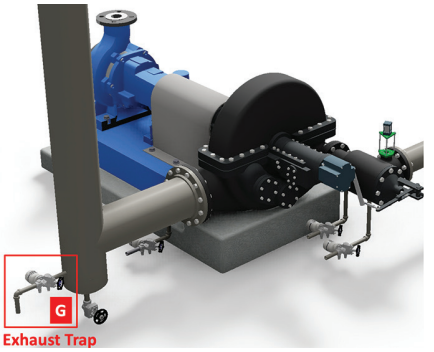

FIG. 16. If an exhaust side trap is not properly installed or maintained, condensate must pool to rise.

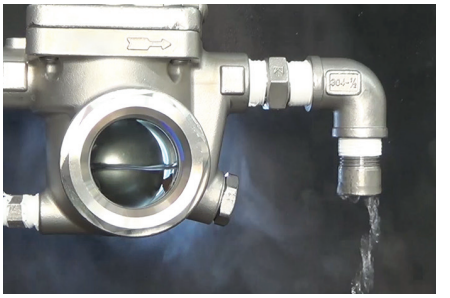

FIG. 17. A correctly selected float trap can discharge condensate immediately, while maintaining a water seal.

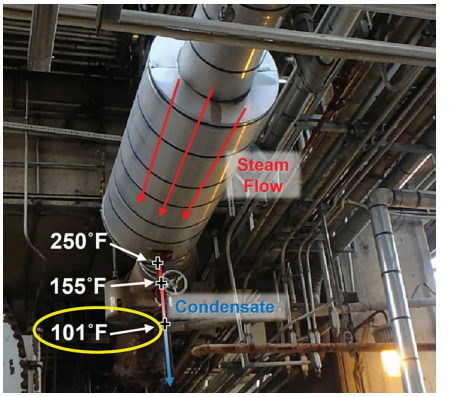

FIG. 18. The low temperature indicates a trap or other blockage failure, reducing separator effectiveness.

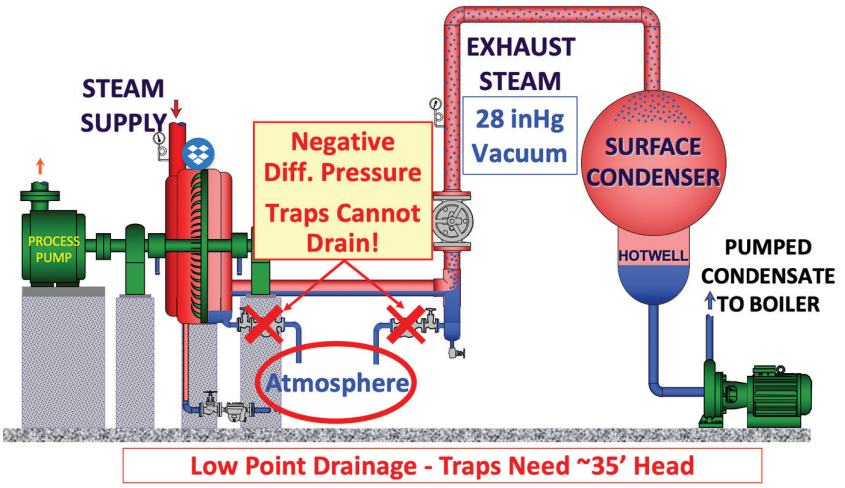

FIG. 19. A trap with supply side connected to vacuum cannot easily discharge to atmosphere.

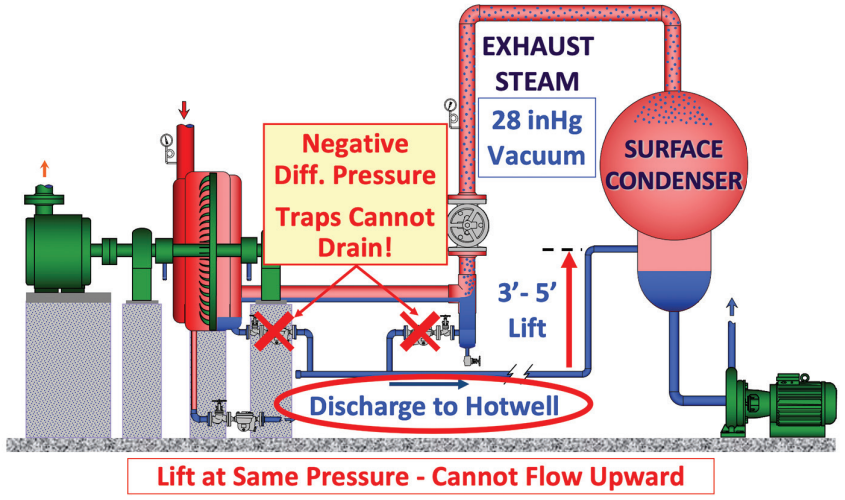

FIG. 20. A trap can only drain into the hotwell if there is sufficient hydraulic head or downward flow by gravity.

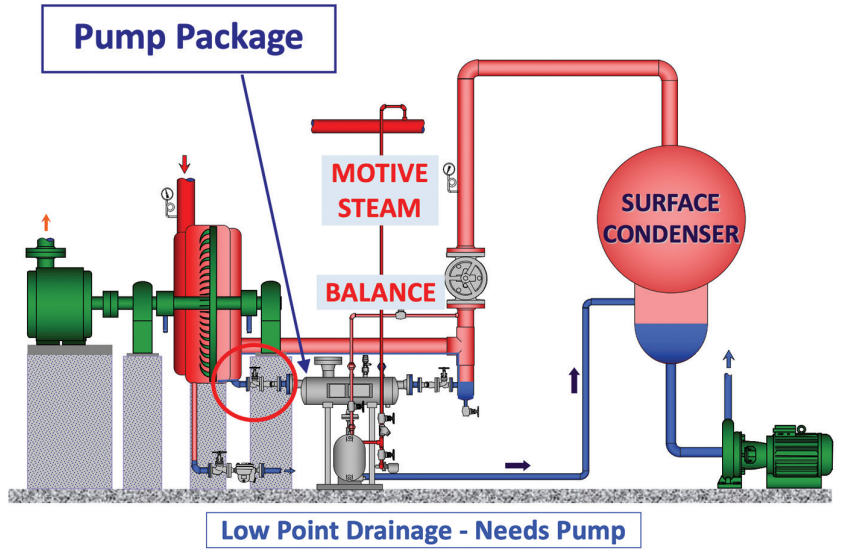

FIG. 21. Getting condensate to flow up to the hotwell requires a pump system when hydraulic head is insufficient.

Virtually every article published by Graham Manufacturing Corporation or such industry experts as J. R. Lines, R. T. Smith, Elliot Spence, Loren E. Wetzel, Norman P. Lieberman, Scott W. Golden and Andrew Sloley—to name a few—recommends the necessity of a well-insulated steam supply line, near saturated steam as the motive source, and comments on the importance of having a steam trap and separator/drain installed before the steam ejector. Even so, it is common to see neither insulation, a steam trap, nor separator/drain before an operating system.

The necessity for insulation and the separation and drainage equipment is to minimize and remove the wetness present in typical steam supply to the ejector. What may not be considered is that the steam velocity exiting the ejector's motive nozzle is in the range of 3,000 ft/sec–4,000 ft/sec.[9] The presence of wetness in the steam has multiple debilitating effects, from reducing the suction to eroding the orifice. Once the orifice diameter is enlarged by 7%, it must be replaced—until that is done, the vacuum is reduced and the steam demand increased. The reduced vacuum strength requires other ejectors to be put into service if additional suction is needed, which can significantly increase the steam used above the flow through the enlarged nozzle (FIG. 23).

An additional common error found on the inter- and after- condensers in an air exhauster system is the balancing of the drain trap (FIG. 24). Improper or non-existent balancing is frequently experienced, and this practice can severely impact the condenser performance due to insufficient drainage from and subsequent reduction of heat transfer duty of a flooded/partially flooded condenser. Close attention should be given to the correct installation and drain trap balancing, as well as maintaining the trap to correct operating condition, to help optimize condenser performance.

Takeaways. Consider these case history-based experiences to help improve steam turbine performance and vacuum system reliability. Begin by improving the quality of steam supplied from the utility headers, supported by proper CDL placement and maintenance (FIGS. 4–10). This is crucial to turbine efficiency and reliability, with-

out which optimization becomes impossible. Then, drain and separate moisture from the steam supply immediately before each turbine. Drive steam can travel a long distance through piping systems that may have insufficient insulation, along lines where there may be insufficient or blocked CDL and, in some cases, where steam is improperly pulled from the bottom of the utility header rather than the top. Plants are complex and it is common that the lines supplying steam to the turbines may have some improper piping practices, so optimizing the steam quality at the turbine's entrance is a best practice recommendation. Properly select and size float traps to provide effective drainage through the turbine itself, as shown in FIG. 13.

Condensing turbines require special considerations when draining from vacuum to atmosphere or into the condenser hotwell, such as pumping condensate or using extremely high hydraulic head to fill a trap with condensate (FIGS. 19–21).

Air exhauster systems are critical to condenser operation, and similar steam-quality and condensate-removal principles are recommended for the steam supplied to ejector systems to optimize nozzle reliability and benchmark performance (FIGS. 22 and 23). Finally, drain traps on inter/after condensers must be properly balanced for proper condenser performance (FIG. 24). HP

ACKNOWLEDGEMENT

The author would like to extend special thanks to Justin McFarland and Tracy Snow for their kind review and comments.

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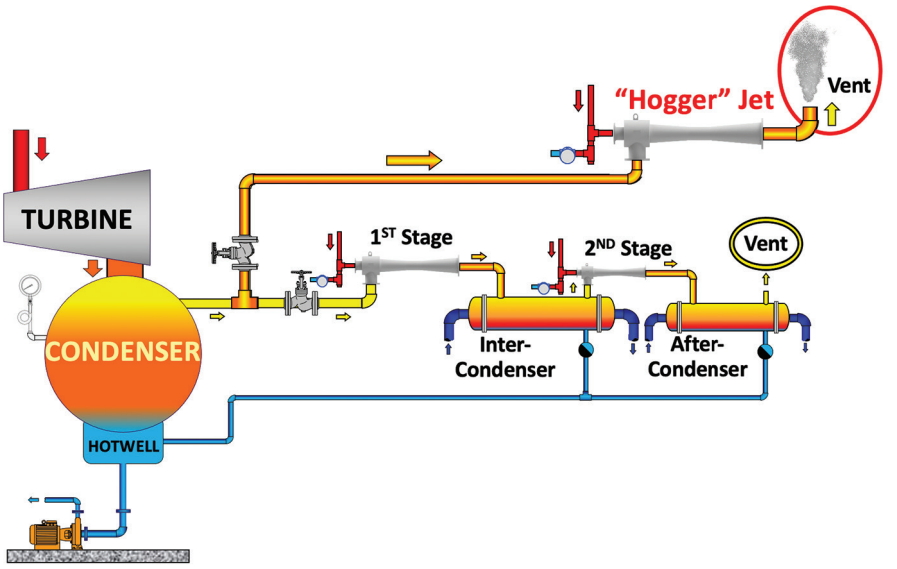

FIG. 22. Optimal ejector entrainment is crucial to effective air removal and system performance.

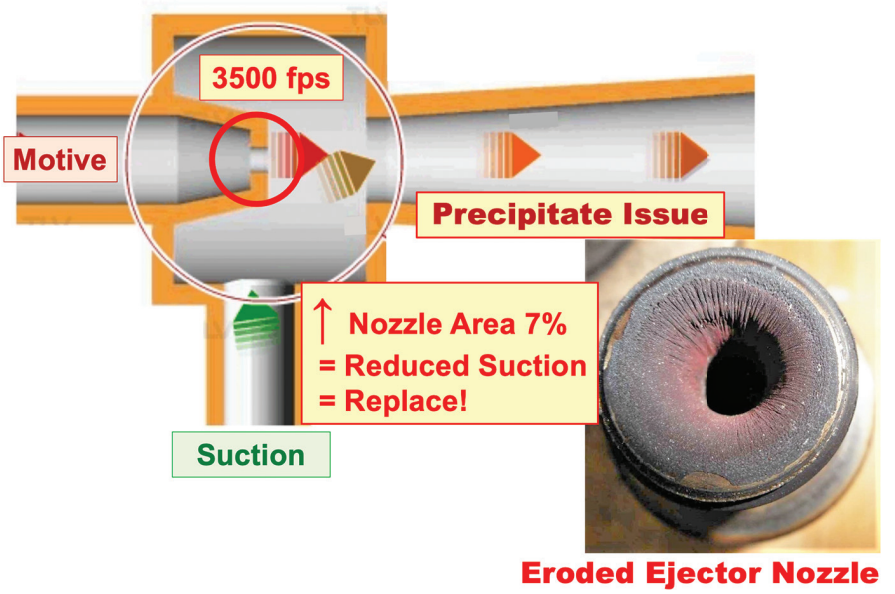

FIG. 23. Poor quality motive steam can cause accelerated wear and costly but weakened performance.

JAMES R. RISKO is President of TLV Corp. and is responsible for U.S. and Canadian operations. He has 46 yr of steam systems experience, has authored more than 60 technical articles, provided webinars to more than 3,000 attendees globally, and presented papers for the Kister Distillation Symposium, Distillation Experts Conclave, Fractionation Research Inc., AFPM, AIChE, the Ethylene Conference, RefComm, IPEIA, IETC, eChemExpo, AEE World and ASHRAE. He co-invented the world's first combination pump/traps and created the "Extended Stall Chart" for draining stalled coils, heat exchangers and reboilers. A past Chairman of the FCI, Risko is active in FCI and ANSI standards development. He is an avid tennis and guitar player and has three energy management certifications. The author can be reached at Risko@TLVengineering.com.

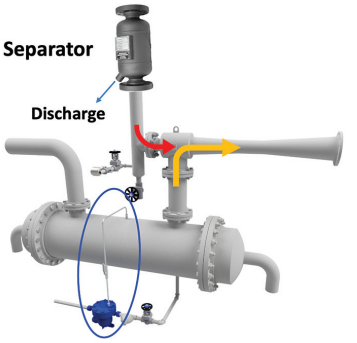

FIG. 24. An improper ⅜-in. to ¾-in. balance connection can severely hinder system operation.

O. OHARRIZ, Belzona Inc., Miami Lakes, Florida, U.S.

Development of novel epoxy closed-cell foam for personnel and corrosion protection—Part 2

Most industrial assets operating at elevated temperatures require thermal insulation for energy conservation, thermal protection or process stabilization. As soon as the insulation is installed and in service, the risk of the underlying substrate suffering from corrosion under insulation (CUI) increases. It should be noted that CUI represents a severe threat to the on-stream reliability of many of today's refining, chemical, power generating, and pulp and paper industries, including onshore and offshore installations. The mechanism of CUI is initiated by the ingress of water into the thermal insulation, which traps the solution at the annular space between the metal substrate and the insulation. As a result, the substrate starts corroding under the insulation. Elevated temperatures exacerbate this corrosion mechanism.

NACE SP0198 defines carbon steel, austenitic and duplex stainless steels as the primary metallic substrates potentially suffering from CUI. In practice, CUI commonly appears in thermal ranges between 50°F and 350°F, or where there is cyclic operation of the equipment. For carbon steels, CUI manifests in the form of uniform and localized corrosion. For austenitic and duplex stainless steels, CUI is normally localized, leading to stress corrosion cracking if appropriate environmental conditions and stress levels are met.[1]

Part 1 of this article (October 2022) detailed the development of a novel epoxy closed-cell foam insulating and corrosion protection barrier by a coating manufacturer. Design considerations of such a material, fitness-for-service testing and results were also presented. Potential application areas and benefits, including worksite personnel and CUI protection, were discussed.

EXPERIMENTAL PROCEDURE

Thermal conductivity (EN 12667/ASME C177). Thermal conductivity is used to measure the ability of a material to conduct heat when in thermal contact with another surface. Two samples of the proprietary epoxy foam[a] were cast and allowed to grow at ambient temperature, as shown in FIG. 4. The samples were sandwiched between a central heating slab (hot plate) and two peripheral flat cooling slabs (cold plates) in a guarded box, as depicted in FIG. 5.

Heat was generated and the temperatures of the sample surface adjacent to both the hot and cold slabs were measured and averaged. The thermal conductivity of the epoxy foam was then calculated based on one-dimension heat transfer equations at sample mean temperatures of –40°F, –4°F, 32°F, 68°F, 140°F, 248°F and 302°F.

FIG. 4. Cast sample of the proprietary epoxy foam[a].

CUI protection (modified ISO 19277). The objective of this test was to subject the epoxy foam[a] to simulated scenarios of multi-phase cyclic CUI and assess its performance based on the possible development of rusting, cracks and/or delamination after exposure. A pipe section constructed of mild carbon steel and of known dimensions was prepared using two different surface cleanliness methods: abrasive blasting to the requirements of SSPC SP 10 and power tool cleaning according to SSPC SP 11. The average

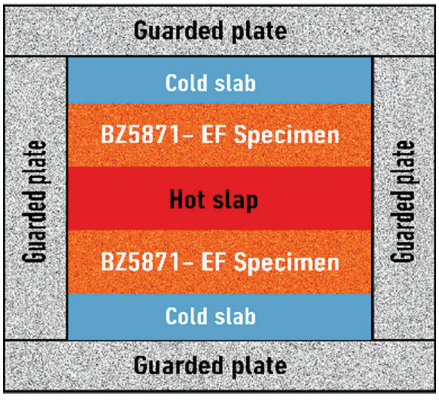

FIG. 5. Schematics of the guarded-hot-plate experimental apparatus.

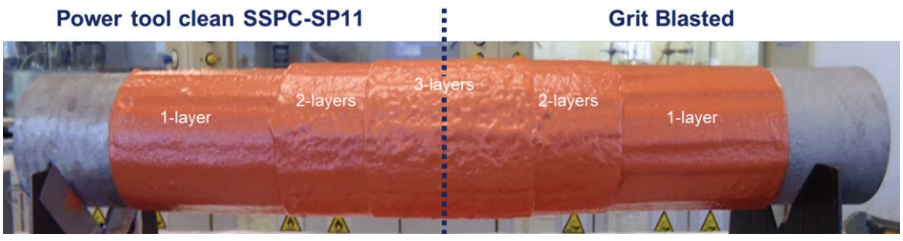

FIG. 6. Specimen for simulated corrosion under insulation testing.

profile of both substrates was measured and found to at least average 3 mil and 2 mil for the SSPC SP 10 and SSPC SP 11 substrates, respectively.

The pipe section was radially encapsulated with the epoxy foam by brush, producing a multilayer finish (consisting of 1-, 2- and 3-layer systems) onto each surface preparation (FIG. 6), and allowed to cure in accordance with the manufacturer's best practices. The pipe section was mounted into a designed CUI rig (FIG. 7) and subjected to thermal cycling, as shown in TABLE 4. The wet periods consisted of a constant deluge of tap water at a flowrate of 0.26 gal/min from nozzles distributed over the axial extent of the coated piping. Two different regimes, CUI-1 and CUI-2, were scheduled for a total duration of 1,000 hr. The test was monitored via an infrared imaging camera, as shown in FIG. 8.

Upon completion of the test, the proprietary epoxy foam[a] was visually inspected for delamination or cracking. Following visual inspection, the foam was completely removed from the pipe section to reveal the underlying substrate, which was assessed for rusting.

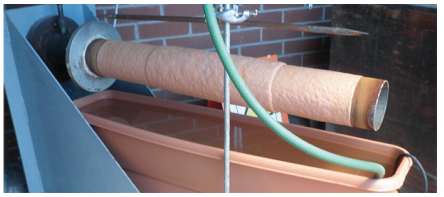

FIG. 7. CUI simulated test rig.

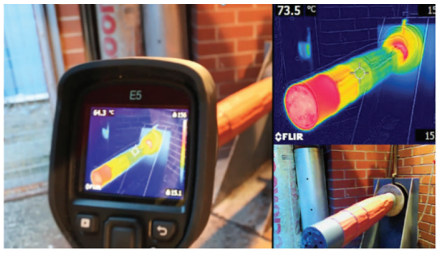

FIG. 8. Infrared imaging monitoring.

FIG. 9. Cured samples—ambient cured sample (left).

Salt spray (ASTM B117). The objective of this test was to subject the epoxy foam to a corrosive environment with an intentional scribed line exposing the substrate and to evaluate its performance based on the possible development of cracks and blistering, as well as its ability to resist the creep of corrosion as a result of substrate attack.

Mild steel panels of known dimensions were prepared to the requirements of SSPC SP 10 with an average substrate profile of 3 mil. The panels were encapsulated with the foam epoxy by 1-layer brush application (FIG. 9). The foam epoxy was cured in accordance with the manufacturer's best practices. The dry film thickness was measured to be 120 mil. One specimen was cured at 68°F while the other was post-cured at 248°F. A vertical 2-in. scribe line was made in the center line of one side of each panel to expose the underlying substrate and encourage corrosion.

The scribed specimens were positioned in a salt spray chamber operating at 95°F, as shown in FIG. 10. The coated panels were exposed to this corrosive environment for 4,500 hr. Upon completion of the exposure, the coated panels were visually inspected to assess the integrity of the epoxy foam, which was then completely removed to expose the underlying substrate and assess for corrosion.

FIG. 10. Salt fog apparatus used.

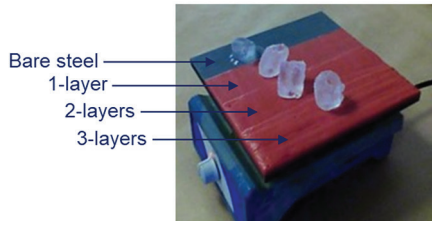

FIG. 11. The epoxy foam[a] multilayer coated surface being heated—ice cubes were used to demonstrate temperature reduction on a coated surface vs. uncoated.

Cool-to-touch properties. The objective of this test was to determine the ability of the epoxy foam to insulate a heated surface by reducing its actual skin temperature to acceptable touch temperatures for contact times longer than 5 sec. Carbon-steel panels of known dimensions were prepared to the requirements of SSPC SP 10 with an average profile of 3 mil. The panels were partially encapsulated with the epoxy foam using 1-, 2- and 3-coat applications at different wet film thicknesses (WFT) of 25 mil, 40 mil and 120 mil, respectively (DFT is three times WFT), as shown in FIG. 11. The acceptable touch temperature and contact time for the test were set up at 140°F and 5 sec, respectively, in agreement with the associated standard and typical regulations set forth for occupational safety[15] in industrial environments. A heater was used as a caloric energy source and a contact thermometer was employed to measure the temperature of both the panel metallic surface and the coated surface (FIG. 12).

The partially coated panels were placed on the hot plate of the heater, and set up at 40°F, 194°F, 248°F and 302°F. The panels were allowed to reach thermal equilibrium before any measurement was taken. The substrate temperatures and thicknesses of the epoxy foam required for achieving thermal reductions below 140°F were plotted.

Thermal cycling (ISO 19277). The objective of this test was to subject the epoxy foam to simulated scenarios of thermal cycling and assess its performance

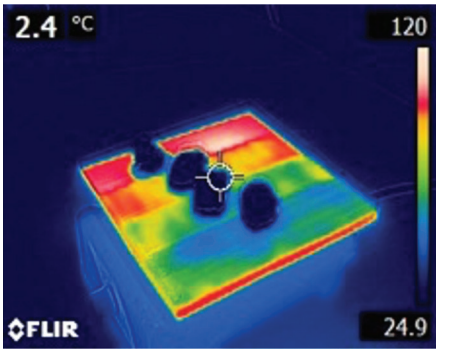

FIG. 12. Infrared image of the panel showing temperature reduction via thermal coloring: less heat (blue/green) and more heat (brighter colors).

based on the possible development of cracks and/or blisters and delamination after exposure. Three mild steel panels of known dimensions were prepared to the requirements of SSPC SP 10 with an average substrate profile of 3 mil. The panels were encapsulated with the foam epoxy by 1-layer brush application. The applied epoxy was cured at 68°F in accordance with the manufacturer's best practices. The dry film thickness was measured to be 120 mil. The panels were placed in the oven and heated until reaching 248°F.

Immediately after, the panels were quenched into ice water covering at least ¾ of the test panels and then left immersed until the temperature of the foam epoxy reduced to –22°F. This test was repeated for 50 cycles per panel. Specimens were inspected for cracking and delamination.

Pull-off adhesion on substrates cleaned to SSPC 10 and SSPC 11 (ASTM D4541). The objective of this test was to subject the epoxy foam[a] to pull-off adhesion testing when applied onto substrates prepared to the cleanliness requirements of SSPC SP 10 and SSPC SP 11. Mild steel panels of 400-mil thickness were prepared to the requirements of SSPC SP 10 (by abrasive blasting) and SSPC 11 (by power tool) with an average substrate profile of 3 mil and 1 mil, respectively. The panels were coated with the epoxy foam by 1-layer brush application. One sample of the epoxy foam per surface preparation method was allowed to ambient cure while the other was post-

FIG. 13. CUI-1 after 1,000 hr of testing: no cracking or delamination were observed in the epoxy foam. No underlying corrosion was detected upon foam removal.

FIG. 14. CUI-2 after 1,000 hr of testing: no cracking or delamination were observed on either power-tool or grit-blasted areas.

FIG. 15. No corrosion for a 2- or 3-layer system was observed upon the removal of the epoxy foam[a]. Minor rust was detected for a 1-layer system.

TABLE 4. Simulated CUI testing protocols

Testing regime	Cycle details
CUI-1	Thermal cycle between 248°F and 140°F with alternating hourly dry/wet periods for 1,000 hr
CUI-2	Thermal cycle between 248°F and 50°F with alternating hourly dry/wet periods for 1,000 hr

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cured, both in accordance with the manufacturer's best practices. The epoxy foam applied on each panel was further pulled off and the results compared.

Testing results and discussion. The range for the epoxy foam was measured to be within 0.03 Btu/ft. h. °F–0.05 Btu/ft. h. °F. Such range of thermal conductivity is comparable to that of vermiculite and silicon dioxide foams, materials used for refractory and insulation purposes in several industries and fireproofing of structural steel and cementitious products. **TABLE 5** shows the results at various mean temperatures.

After 1,000 hr of simulated CUI-1 regime testing, coated multi-layer sections on grit-blasted and power tool-cleaned substrates exhibited no failure, as shown in **FIG. 13.** Neither cracking nor delamination of the epoxy foam were detected. When the insulation was removed by mechanical means, no corrosion was found in the bondline between the substrate and the epoxy foam. After 1,000 hr of simulated CUI-2 regime testing, coated multi-layer sections on grit-blasted and power tool-cleaned substrates exhibited neither cracking nor delamination of the epoxy foam (**FIG. 14**). The insulation was mechanically removed. No corrosion was found on the substrate protected with a 2- or 3-layer epoxy foam (**FIG. 15**). Rust was spotted on the substrate onto which the epoxy foam was applied in 1 layer. This result indicates that the epoxy foam as a 1-layer system should not be recommended for wet service at 248°F.

After subjecting both samples (ambient-cured and post-cured) to 4,500 hr of spray testing, no delamination or cracking were observed (**FIG. 16**). Rust developed in the vicinity of the scribed lines, as it can be seen once the foam was removed (**FIG. 17**).

The thickness of a 3-coat system of the proprietary epoxy foam[a] was enough to reduce the surface temperature of 302°F to <140°F. Due to the reduction in surface temperature, hand contact can be maintained for longer than 5 sec without burn injuries. Neither cracking nor delamination were observed in any of the panels, as shown in **FIG. 18.**

The results can be seen in **TABLE 6.** In all cases, the epoxy foam resulted in cohesive failure, which implies that the foam was still tightly adhered to the profile when pulled. The surface cleanliness method did not affect the results in any way, which confirms that the epoxy foam is tolerant to minimal surface preparation.

Takeaways. Several conclusions can be drawn from the development of the epoxy foam. First, the foam uses a solvent-free phenol formaldehyde Novolac epoxy as a base and a polyamine as a solidifier—they react following a typical mechanism of nucleophilic addition to yield a thermosetting polymer. The functionality and chain length of the epoxy resin, solidifier and modified polysiloxane blowing agent are proprietary, but they are used to determine the crosslink density of the foam, and therefore influence its nature, rigidity, closed-cell structure, strength and thermal insulation properties.

Next, the epoxy offers both excellent proven corrosion protection in CUI and water immersion scenarios and thermal insulation, which renders it as an ideal solution for equipment operating at elevated temperatures. It offers safe touch for operators working in hot environments by reducing the surface temperature of industrial assets below 140°F for longer than 5 sec of direct hand contact.

Finally, the epoxy foam offers an array of additional practical features, including ease of application, short-over coat times, durability, tolerance to minimal surface preparation, and quick return to service, among others. HP

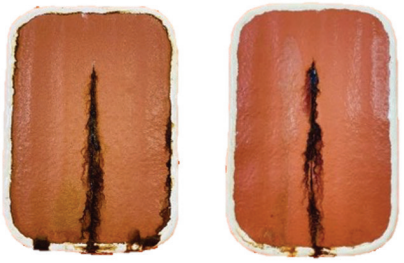
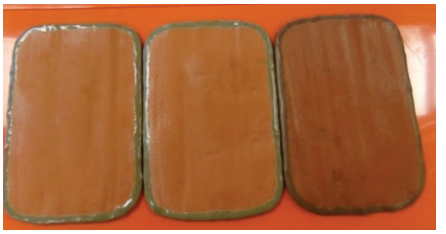


FIG. 16. Salt spray after 4,500 hr of testing: the ambient-cured sample after testing (A), and the post-cured sample after testing (B).

TABLE 5. Thermal conductivity of the epoxy foam[a]

Sample mean temperature, °F	Thermal conductivity λ (Btu/ft. h. °F)
–40	0.0373
–4	0.039
32	0.0403
68	0.0418
140	0.0445
248	0.0488
302	0.0505

FIG. 17. The ambient-cured sample after testing and foam removal (A), and the post-cured sample after testing and foam removal (B).



FIGS. 18. Panels after exposure to thermal cycling.

TABLE 6. Pull-off adhesion

Pull-off adhesion, psi			
SSPC SP 10		**SSPC SP 11**	
Ambient-cured	650	Ambient-cured	620
Post-cured	530	Post-cured	680

ACKNOWLEDGEMENT

This paper was presented by the author or assigned speakers at the Coatings+ 2021 conference.

NOTE

[a] BZ5871-EF epoxy foam

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Obsolescence management in a manufacturing unit

Obsolescence is one of the most detrimental and worrisome issues in manufacturing units. This is predominantly because of rapid advancements in technology. Consistent innovations and development in this era are throwing existing devices and equipment into the obsolescence basket. Similar performing products are being introduced continuously by competitors, with enhanced features and greater capabilities that can yield optimum performance for users.

Original equipment manufacturers (OEMs) are finding that existing products do not generate enough revenue, forcing the withdrawal of support for the supply of spares and services. Compulsion forces most end users to take knee-jerk actions for sustenance. The small business houses continue operation with limping equipment, which leads to unwanted outages of units, resulting in fiscal losses. Conversely, big houses immediately infuse capital expenditure (CAPEX) for upgrades/revamps of obsolete equipment for production continuation. These monetary transactions come as an immediate means of survival and happen on an extemporary basis without a clear path of progress to tackle the issue more systematically.

This article details incremental threat management of obsolescence in a manufacturing unit, detailing how to build a management system to tackle obsolescence before it cripples production units.

Apart from the vast amount of CAPEX involved, the production unit must be stopped for a prolonged period since upgrades may not be possible while the unit is operating. This means that tackling obsolescence must be a carefully considered action based on meticulous techno-economic analysis. Equipment obsolescence in a manufacturing unit is a natural phenomenon and can happen anytime.

Establishing a process of obsolescence management in a manufacturing business is paramount so that a systematic plan is in place to counter the obsolescence threat. Organizations must identify potential obsolescence through the system and display the desire to move from a reactive obsolescence management program to a proactive process. The end users must act in advance to avoid the yielding phase of a production unit. A systematic obsolescence management process must be in place to tackle this issue before it cripples production.

An obsolescence issue in a manufacturing unit may arise due to many reasons. Equipment is under supplier or technical obsolescence when the OEM withdraws support for spares and services. Sometimes, a business decision is taken to stop using equipment and its spares due to costs or health, safety and environment (HSE) considerations. This is user-specific/functional obsolescence. Economic obsolescence involves replacing/upgrading critical equipment because it has outlived its usefulness or is beyond economical repair.

Among these, technical obsolescence is the most worrisome issue for a production unit, and the threat of equipment becoming irrelevant during its lifecycle looms. Critical equipment faces outages due to the unavailability of OEM support, which challenges manufacturers to continue uninterrupted production without critical obsolete equipment.

Generally, OEMs extend support in two phases: warranty and post-warranty support. In the warranty support stage, OEMs confirm the availability of the product. During this phase, OEMs extend all spares and services support for the product. This phase spans out up to 5 yr after the product is introduced to the market. Subsequently, the product enters the end-of-life and end-of-service (EOS) stages. These stages are between 5 yr and 8 yr after the product launch.

In the post-warranty support stage, the OEM ends all equipment development and declares limited support for the product. This is the penultimate stage before the product is phased out, known as the end-of-development phase. Generally, it becomes prominent within 8 yr–14 yr of the product's lifecycle.

The ultimate phases of the product are the EOS life and end-of-support phases. In these phases, the OEM declares the product obsolete and indicates EOS and the unavailability of any product updates. In this stage, the OEM stops selling equipment spares and service contract renewals for maintaining the equipment. Typically, this phase appears within 14 yr–20 yr of the product's launch. Beyond this phase, the equipment becomes completely obsolete and continuing to operate it becomes challenging and costly.

When the obsolescence phase engulfs an operation unit, it experiences frequent downtime due to the absence of virgin spares and OEM services. There is an added risk of damaging credibility with customers if a plant fails to meet anticipated output.

Additionally, attempts should be made to reduce maintenance costs by reducing rush orders due to obsolete equipment spares. It is also paramount to increase plant safety levels by timely decommissioning and disposing of obsolete equipment.

Therefore, a process of obsolescence management must be in place that enables a mitigation plan to be framed before it impacts the production unit. The following is a general framework for the process:

- **Step 1:** Identify obsolescence and proactively implement risk mitigation strategies to improve reliability. The identification of potentially obsolete equipment should be carried out through various tools such as a root cause analysis report, a recurring failure report, a report on the plant's mechanical integrity, a corrosion and inspection report, and various safety audit reports published as a part of internal management's practice for a manufacturing unit. These reports will expose the obsolete production equipment, as well as those underperforming because of a lack of OEM support. Even a substantial increase in equipment maintenance cost will be brought under the scope as spares and service contracts for obsolete equipment become high.
- **Step 2:** The engineering team must assess the extent and scope for all potential obsolete equipment as identified in Step 1. It may be the entire piece of equipment or a component of the equipment that becomes obsolete. The most common partial obsolescence cases are the components of a system where the sub-supplied items become obsolete more quickly than the original equipment, which may still be in the production phase.
- **Step 3:** In the case of partial obsolescence, a technical discussion must be conducted with alternative suppliers who can provide the same obsolete components compatible with the original equipment. This may provide assurance for the continued functioning of the equipment without any stoppage due to obsolescence. For example, the third-party interfacing unit or the human-machine interface unit of a process control system can be developed for outsourcing from alternative vendors in case of obsolescence. This may prevent the revamp of the control system.
- **Step 4:** The lifecycle strategy must be worked out for all identified critical obsolete equipment so that a 5-yr plan for equipment upgrades may be developed. The following data must be collected before developing an equipment lifecycle plan:
  - Equipment criticality (HSE/production)
  - Equipment installation base
  - Time of obsolescence declared by OEM
  - Extent of spares/service support available by OEM for obsolete equipment and the time frame till the OEM continues support
  - Available spares
  - Rate of consumption of spares
  - Failure rate of the equipment.
- **Step 5:** Assess the expected obsolescence phase based on the lifecycle strategy. Decide on whether a complete or partial upgrade will be executed and identify the proposed phasing of the upgrade. A product might be declared obsolete by the OEM, but the end user may opt for a staggered action plan depending on the respective phase of obsolescence. The obsolescence phase is determined based on the lifecycle plan of the equipment.
- **Step 6:** Work out the mitigation plan for the impact created due to no available alternatives. In that case, the process design might need to be changed to accommodate the absence of alternatives until the revamp/upgrade of the system is implemented.
- **Step 7:** Conduct the cost-benefit analysis of spares/service support and decide whether to stock up on spares/service support or look for an immediate upgrade.
- **Step 8:** Have a technical discussion with the OEM to evaluate alternatives with assorted options for required changes/upgrades. The upgrades may contain enhanced features that enable the equipment to function more efficiently, and the enhanced features are to be weighed while evaluating the main equipment function.
- **Step 9:** Conduct a techno-commercial assessment and negotiate with suppliers to evaluate various upgrade options.
- **Step 10:** Decide whether a complete or a partial upgrade will be executed and identify the proposed phasing of the upgrade.
- **Step 11:** Define the specification sheet for the new equipment.
- **Step 12:** Develop preliminary upgradation budget requirements based on the identified obsolete equipment and evaluate alternatives.
- **Step 13:** Compare the preliminary budgetary requirements with guidelines from the annual planning process (in terms of allocation) and evaluate overall maintenance/shutdown schedules to determine schedules.
- **Step 14:** Prioritize budgetary requirements and define the upgradation timeline for each obsolete equipment. In case of deferral, work out additional alternative strategies for obsolete pieces of equipment.
- **Step 15:** Obtain management approval for the upgradation budget.
- **Step 16:** The progress and efficacy of the obsolescence management program must be monitored periodically. The following suggested key performance index can be followed:
  - The frequency of production outages or HSE incidences due to obsolete equipment
  - The ratio of obsolete inventory and total inventory
  - The ratio of equipment covered under the obsolescence management program and the equipment in which potential obsolescence is identified
  - The amount of equipment with an obsolescence plan.

Obsolescence phases. The phases of obsolescence include the following:

- Phase 1: Upgradation within 1 yr
- Phase 2: Upgradation within 2 yr
- Phase 3: Upgradation within 3 yr
- Phase 4: Upgradation within 5 yr.

The process for obsolescence management may be adopted in different versions. However, before obsolescence issues become a critical problem, forcing emergency decisions, obsolescence must be addressed at an appropriate time to develop a mitigation plan accordingly. HP

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Decarbonizing your fired heaters with hydrogen fuel

Hydrogen (H_2) has long been considered a high-value product, but not typically as a fuel for fired equipment. However, as the world seeks cleaner, more sustainable solutions, H_2's unique property of producing zero carbon dioxide (CO_2) when combusted has been gaining attention. H_2 may be the "silver bullet" for eliminating CO_2 emissions in fired heaters. However, making the switch does come with challenges. **FIG. 1** represents the potential to reduce yearly CO_2 emissions in a 100-MMBtu/hr (fired duty) heater.

Challenges. As a basic building block of life and the most abundant element in the universe,[1] H_2 is a unique molecule with unique challenges. However, without attachment to carbon, it is a vastly different molecule with distinctive properties when combusted. The following are some of the potential challenges associated with switching to all or partial H_2 firing:

- Higher flame temperature
- Higher flame speed
- Flame visibility (or lack thereof)
- Radiant/convection duty split
- Impact to radiant heat transfer
- Corrosion mechanisms
- Changes to safety and control methods
- Burner piping and fuel gas skid resizing
- Stack plume visibility.

High-temperature flame. Increasing the amount of H_2 in fuel gas has a significant impact on the flame temperature, as shown in **FIG. 2.** While **FIG. 2** is based on the adiabatic (i.e., theoretical) flame temperature, it highlights that a 100% H_2 flame can be hundreds of degrees hotter than a flame from hydrocarbon fuels. The primary issue with this effect is that the formation of thermally generated nitrous oxides (NO_x) increases proportionally with flame temperature.[2]

Fortunately, several options can counteract the increase in NO_x emissions. Burner design modifications (i.e., retrofit) can be considered first. External flue gas recirculation and/or steam injection may also be implemented to lower the flame temperature. If these methods are insufficient, selective catalytic reduction may be required.

High flame speed. Flame speed—the rate at which a combustion reaction takes place for a given fuel—is a critical variable in fired heater design and operation. To use a simplified scenario, it can be conceptualized as the speed at which a gas will fully combust if the gas was contained in a long tube and ignited at one end. In actual practice, flame speed depends on several factors, including pressure, temperature, fuel composition, excess air, turbulence and surrounding cooling effects.[3] However, in an idealized environment consisting of laminar flow at 77°F and 14.7 psia of pressure, a tube filled with H_2 and lit at one end will complete the combustion reaction at the opposite end of the tube roughly 7× quicker than a tube filled with methane (**FIG. 3**).[3,4]

To ensure reliable, safe combustion in a process burner, it is vital to control the speed of the un-combusted air/fuel mixture so it is appropriately matched to the speed of combustion or flame speed. If the air/fuel speed is lower than the flame speed, the combustion reaction can travel backward into the burner and upstream equipment (i.e., flashback). Flashback potential is especially important to consider for pre-mix burners.[2] Therefore, before switching to H_2 fuel from hydrocarbon fuel, it is essential to review the burner design to ensure it can accommodate the air/fuel speeds necessary for safe operation.

Flame visibility. The ability to verify the presence of a stable flame at each burner is paramount to safely operating a fired

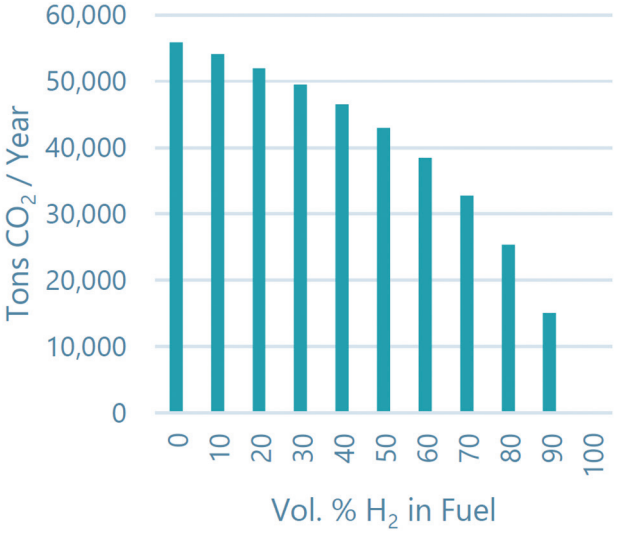

FIG. 1. Yearly CO_2 emissions in tpy vs. vol% H_2 in fuel for a 100-MMBtu/hr (fired duty) heater. This assumes the balance of fuel is CH_4, with 15% excess air.

heater. Usually, this can be done by visual inspection or with conventional flame scanners when firing hydrocarbon fuel gases. However, when 100% H_2 is used as a fuel source, the flame becomes virtually invisible. This is demonstrated in **FIG. 4A,** in which a burner firing 100% H_2 can be seen. In contrast, **FIG. 4B** depicts nearly all H_2 combustion with a small percentage of natural gas.[5] Clearly, a small quantity of natural gas in the fuel can dramatically enhance the ability to see the flame.

In situations where hydrocarbon fuel gas is unavailable or not allowed, alternate methods of detecting the flame, such as specialized ultraviolet flame scanners or sound monitors, may be potential solutions.

Radiant/convection duty split. As represented in **FIG. 5,** increasing H_2 content in the fuel can significantly decrease the quantity of flue gas generated.

For an existing heater being revamped to run on H_2 fuel, this reduction in thermal mass traveling through the convection section decreases the heat absorbed. In a single service heater (i.e., the same service in the convection and radiant section), this may be counteracted by increasing the heat absorbed in the radiant section, with careful attention paid to the increased radiant flux, bridgewall temperature and tube metal temperatures. However, if there is a second, independent service in the convection section, the convection coil must be reconfigured to maintain the original heat absorbed. The effects on draft and fan operation, as applicable, should also be considered. Excess air may be increased to generate more thermal mass; however, this will also increase NO_x emissions and reduce efficiency.

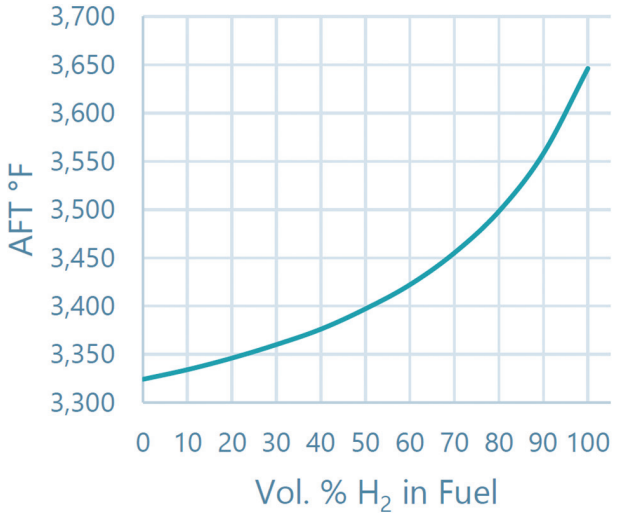

FIG. 2. Adiabatic flame temperature (AFT) in °F vs. vol% H_2 in fuel. This assumes the balance of fuel is CH_4, with 15% excess air.

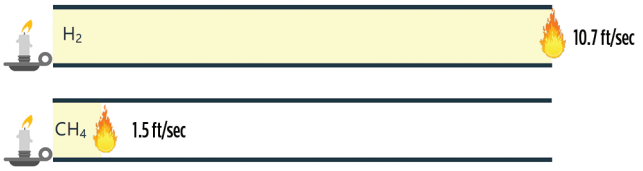

FIG. 3. Graphic depicting the approximate laminar flame speed of hydrogen vs. CH_4 at 77°F and 14.7 psia of pressure.[3]

Impact to radiant heat transfer in the firebox. In the firebox (radiant section), heat is transferred to the process tubes by three main methods of radiation:[2]

- Direct radiant from the flame (i.e., flame burst)
- Reradiation from flue gases
- Reradiation from refractory surfaces.

The radiation from the flame is related to its luminosity and may impact heat transfer. Luminous radiation is the radiation from solid particles suspended in the flame.[6] For example, an oil flame has three to four times more flame radiation due to increased luminosity created by soot content.[2] For a flame from pure H_2, luminosity is reduced to virtually zero, which may decrease the radiant heat transfer slightly.

However, contribution from direct flame radiation is typically low vs. other forms of radiation in the firebox, as evidenced by combination oil and gas burners that have been in operation with little change in performance noted between fuels fired.[2]

Reradiation from flue gases occurs primarily from CO_2, H_2O and sulfur dioxide (SO_2) molecules.[7] Symmetrical molecules [nitrogen (N_2), O_2 and carbon monoxide (CO)] are considered "transparent" and do not reradiate heat.[7] An all-H_2 flame produces significantly more H_2O, which has higher emissivity than CO_2. Since CO_2 is eliminated entirely from the flue gas and is essentially replaced with H_2O, this will have the tendency to increase radiant heat transfer.

As mentioned previously, a H_2 flame has a higher temperature than a methane (CH_4) flame, which may increase the surface temperature of the refractory that is in close proximity to

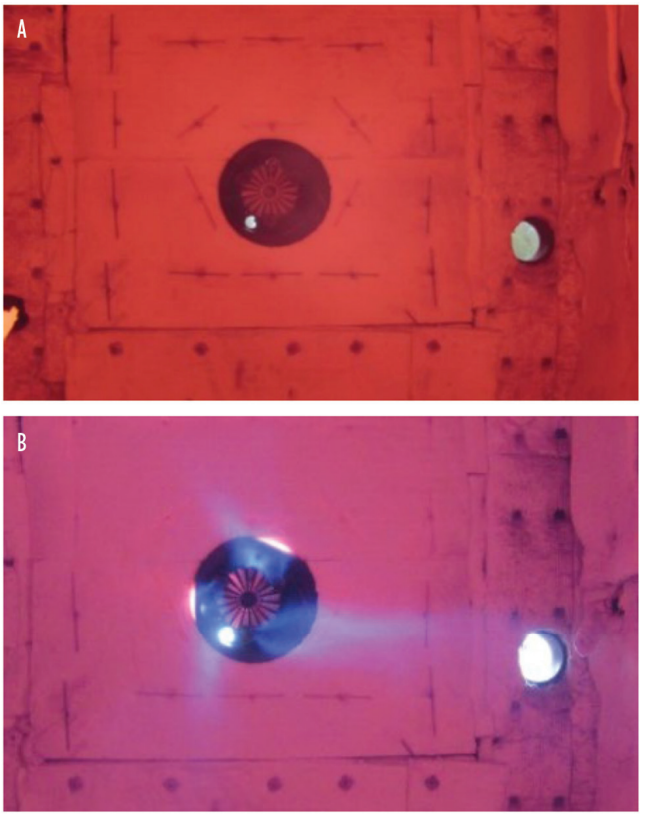

FIG. 4. Picture (A) of a process burner firing 100% H_2, and a process burner (B) firing mostly H_2 with a small percentage of natural gas.[3]

the flame. This may also increase heat transfer in the radiant section. While a reduction in luminosity may reduce direct radiation from the flame, increased emissivity of flue gas molecules and increased refractory temperatures will likely offset this effect, suggesting that current methods for radiant heat transfer calculation are adequate for H_2 firing. The authors' company recently performed a study of a petrochemical heater designed for and operating with up to 90 vol% H_2 fuel. The study found that the predicted firebox temperature and the field measured temperature matched very closely (within 5°F).

Potential corrosion mechanisms. The industry standard for corrosion mechanisms (API 571: "Damage mechanisms affecting fixed equipment in the refining industry") mentions the three major corrosion mechanisms involving H_2:[8]

- H_2 embrittlement (HE)
- H_2 stress cracking from exposure to hydrofluoric acid (HSCHF)
- High-temperature H_2 attack (HTHA).

HSCHF can be ruled out under the assumption that no hydrofluoric acid is involved in this application. That leaves HTHA and HE: HTHA typically occurs at high temperature and pressure (refer to API 941 for temperature and pressure limits for various materials); while HE typically occurs at lower temperatures (< 300°F) and pressures at or near atmospheric.

In both mechanisms, atomic H_2 (as opposed to molecular H_2) forms and diffuses into steel. Once inside the steel, it can react with the carbon to form CH_4, which can create pressure and cracking.[8]

Fuel gas delivery systems typically do not operate at high enough pressure for HTHA to be a concern. High-strength steels with high hardness numbers can be susceptible to HE. According to API 571, the effect is pronounced at temperatures from ambient to about 300°F, corresponding to the range of most fuel gas systems.[8] While the softer carbon-steel piping typically used is generally not susceptible to HE, welds, bolted connections and burner internals comprised of high-strength steel may be areas of concern. Careful review of the fuel gas delivery system should be performed before switching to H_2 fuel.

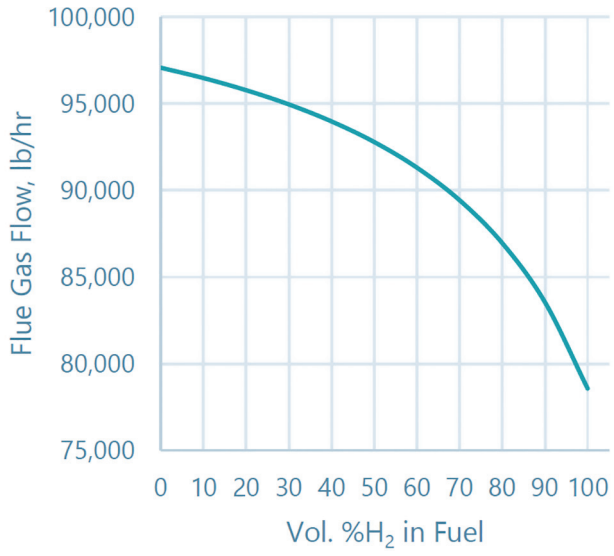

FIG. 5. Flue gas flowrate vs. vol% H_2 in the fuel for a 100-MMBtu/hr (fired duty) heater. This assumes the balance of fuel is CH_4, with 15% excess air.

Safety and controls. H_2 has a wide range of flammability in air, approximately 4 vol%–75 vol%.[9] These properties give H_2 the National Fire Protection Association's (NFPA's) highest flammability rating of 4.[9] While CH_4 also has a flammability rating of 4, it requires more energy to ignite and is easier to detect.

Due to its low molecular size, H_2 may be susceptible to leakage in fuel gas piping designed for hydrocarbon fuels. H_2 gas is colorless and odorless. Due to its high diffusion rate in air, H_2 does not blend well with the comparatively heavier mercaptans that are added to CH_4 to give it an odor. Therefore, H_2 leak detection instruments may need to be added to a fuel gas system before switching to 100% H_2 firing.

H_2 fuel also requires significantly less air to combust stoichiometrically vs. CH_4. This is a key point to remember, especially if switching between H_2 and CH_4 fuels while the heater is in operation. When firing H_2, the heater controls should be adjusted to reduce the combustion air. However, if a switch back to CH_4 fuel is made quickly, without sufficient adjustments to increase combustion air, the CH_4 will not fully combust and creates a potentially unsafe, fuel-rich environment. A fuel gas system that accurately measures the fuel gas composition and controls the combustion air accordingly is critical.

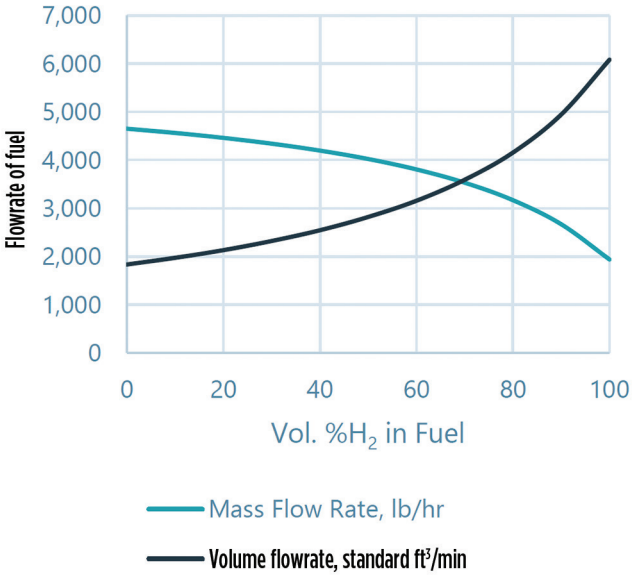

FIG. 6. Mass and volumetric fuel gas flowrate with increasing vol% H_2. This assumes a 100-MMBtu/hr (fired duty) heater, the balance of fuel is CH_4, with 15% excess air. As such, the fuel gas skid and burner piping leading to the heater should be carefully reviewed to ensure proper pipe sizing for acceptable hydraulics.

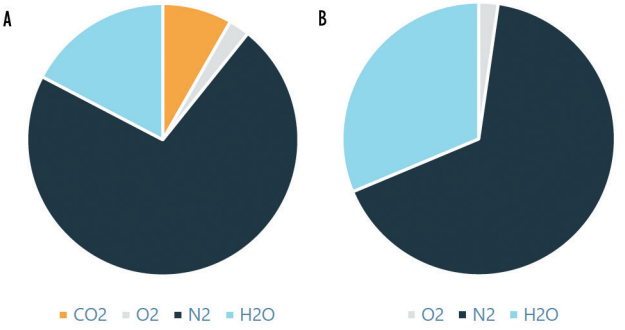

FIG. 7. Chart A shows vol% flue gas composition with 100% CH_4 fuel and 15% excess air, and Chart B shows vol% flue gas composition with 100% H_2 fuel and 15% excess air.

Burner piping and fuel gas skid sizing. For a given heat release, 100% H_2 fuel requires significantly less mass flowrate than CH_4. However, the volumetric flowrate required is more than three times as high, as displayed in **FIG. 6.**

Stack plume. The key variable contributing to the visibility of flue gas exiting a stack is its water content.[10] After exiting the fired heater, hot flue gas cools and the water in the flue gas condenses, often creating a visible white fog. Although not necessarily harmful, this visible water plume may become a nuisance to neighboring communities and act as a transport medium for other pollutants in the gas. This poses a potential challenge as combusting higher quantities of H_2 yields higher quantities of water in the flue gas. As demonstrated in **FIGS. 7A** and **7B,** with 100% H_2 fuel, the water content in the flue gas increases to approximately one third of the flue gas volumetrically.

The water content may be reduced by burning less H_2 in the fuel. If this is not an option, the end user may consider a system to reduce the water content in the flue gas. This could be accomplished by diluting or reheating the gas before it exits the heater. Alternatively, methods to condense and collect the water may be considered.

TABLE 1. Partial experience list with high-vol% H_2 fuel fired heaters

Heater type	Region	Fired duty, MMBtu/hr	Max. vol% H_2 in fuel
EDC cracker	Asia	97	100%
Petrochemical heater	Middle East	594	91%
Petrochemical heater	Middle East	148	86%
CO boiler	North America	195	80%
Delayed coker	Asia	174	78%
CCR platformer	North America	377	64%
Delayed coker	Middle East	160	65%

Making fired heaters H_2-ready. Clearly, many unique challenges are associated with designing and converting fired heaters to H_2 fuel firing. However, the potential to reduce CO_2 emissions in a fired heater is unlimited if 100% H_2 fuel is utilized. Furthermore, the challenges are not new to the authors' company, which has been designing fired heaters with high H_2 fuel content for decades. A partial list of recent relevant experience is provided in **TABLE 1.**

Making the switch to H_2 fuel is an exciting, yet challenging endeavor. Teaming up with experienced fired heater experts is a vital step in the development of safe, effective solutions to the many challenges involved. HP

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Mechanical design challenges in high-temperature electric heaters

Electric heaters are used in the process industries as an alternative to fired heaters or process heaters—where the heating medium is either steam or any heating fluid—for some specific applications where the process duties are low but fluids are heated to high temperature. Due to high-temperature service, electric heaters are exposed to very high external loads imposed by the piping system connected to the nozzles of the heater shell. Moreover, the shell size of the electric heater is small due to lower process heat duty and a high temperature difference between the heater elements and the process fluid, and are designed out of pipe material with standard pipe schedule thickness.

The initial mechanical designs of the shell and nozzle are carried out by electric heater suppliers as per specified design code based on the specified design pressure and temperatures. The thermal expansion loads from the piping system are not considered since they are made available to the heater suppliers at a later date after the finalization of the piping system around the electric heater. The issue is further aggravated if heaters are located at an elevated place where the wind load from the piping system is combined with thermal loads and further increases the primary and secondary loads on the heater shell and nozzles, increasing the chances of heater failure at the shell-to-nozzle junction.

Therefore, a careful evaluation must be done to determine the most economical external load combinations[1] to ensure minimum impact on the thickness of the shell and nozzles already calculated based on the applicable pressure design code. This is usually done by a simulation study to arrive at the correct thickness of the shell and nozzle before the piece of equipment goes for fabrication.

This article will detail a simulation study of a high-temperature vertical electric heater 6-in. NB pipe located on a tall structure (FIG. 1) and will demonstrate the impact of various combinations of external loads—namely Sustained, Thermal and Occasional—on the thickness of the shell and nozzle. The optimum combinations of these loads to limit the local stresses on the shell and nozzle junction within the allowable stresses are recommended.

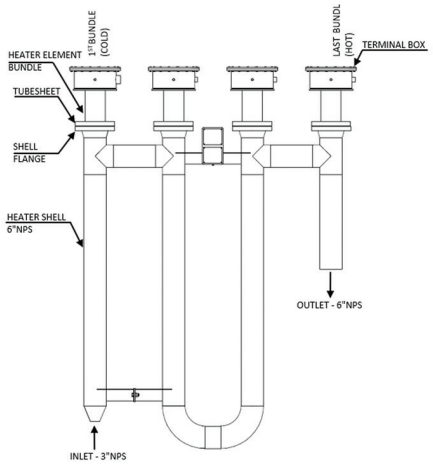

FIG. 1. Electric heater oriented vertically.

TABLE 1. Allowable external piping loads on standard pressure vessel

Nozzles	Force (N)			Moment (N-m)		
	F_x	F_y	F_z	M_x	M_y	M_z
Inlet (3 in.)	2,930	2,340	2,930	720	1,170	920
Outlet (6 in.)	7,740	6,190	7,740	3,610	5,840	4,590

TABLE 2. External piping loads on heater vessel

Nozzles	Type of loading	Force (N)			Moment (N-m)		
		F_x	F_y	F_z	M_x	M_y	M_z
Inlet (3 in.)	Thermal load (design)	–589	–1,915	721	–1,981	–401	–1,860
	Thermal load (operating)	–590	–1,816	356	–1,954	246	–1,758
	Dead weight (operating)	–24	–368	–1	–250	16	30
	Wind	711	216	370	246	438	172
		F_x	F_y	F_z	M_x	M_y	M_z
Outlet (6 in.)	Thermal load (design)	1,214	–6,610	4,975	1,538	242	2,522
	Thermal load (operating)	1,130	–6,024	4,643	1,409	225	2,344
	Dead weight (operating)	–27	–2,071	–69	–87	–4	–59
	Wind	497	2,705	526	1,278	379	1,215

Design conditions. The design and operating pressures and temperatures comprise:

- Design pressure: 0.625 MPa (g)
- Design temperature: 690°C
- Operating pressure: 0.19 MPa (g)
- Operating temperature at inlet: 130°C
- Operating temperature at outlet: 649°C.

Materials of construction comprise:

- Heater shell: SA312-TP304H
- Nozzle: SA-403-TP304H (conical fitting)/SA-312-TP304H (pipe).

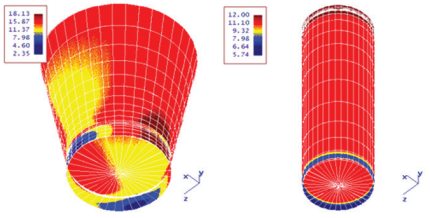

FIG. 2. Load Case 1 (Sustained): Primary membrane stresses at the inlet and outlet for SCH 40S.

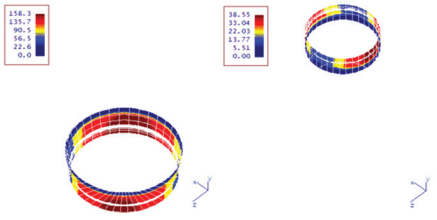

FIG. 3. Load Case 1 (Thermal): Primary membrane stresses at the inlet and outlet for SCH 40S.

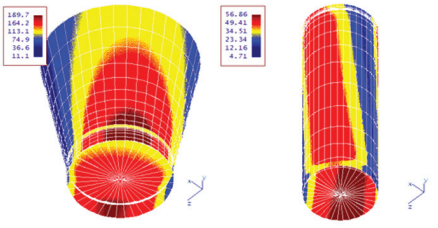

FIG. 4. Load Case 1 (Occasional): Primary membrane stresses at the inlet and outlet for SCH 40S.

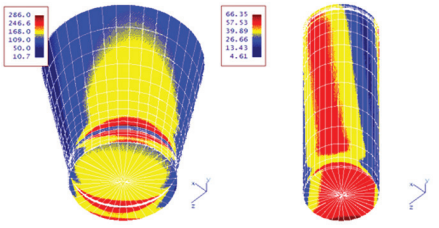

FIG. 5. Load Case 1 (Occasional): Primary + secondary + bend stresses at the inlet and outlet for SCH 40S.

TABLE 3. Load Case 1 and Load Case 2

Load Case 1

Nozzles	Type of loading	Force (N)			Moment (N-m)		
		F_x	F_y	F_z	M_x	M_y	M_z
Inlet (3 in.)	Sustained loads	–24	–368	–1	–250	16	30
	Operating loads	–613	–2,283	720	–2,231	–385	–1,830
	Occasional loads	–1,324	–2,499	1,090	–2,477	–823	–2,002
		F_x	F_y	F_z	M_x	M_y	M_z
Outlet (6 in.)	Sustained loads	–27	–2,071	–69	–87	–4	–59
	Operating loads	1,187	–8,681	4,906	1,451	238	2,463
	Occasional loads	1,684	–11,386	5,432	2,729	617	3,678

Load Case 2

Nozzles	Type of loading	Force (N)			Moment (N-m)		
		F_x	F_y	F_z	M_x	M_y	M_z
Inlet (3 in.)	Sustained loads	–24	–368	–1	–250	16	30
	Operating loads	–614	–2,184	355	–2,204	262	–1,728
	Occasional loads	–1,325	–2,400	725	–2,450	700	–1,900
		F_x	F_y	F_z	M_x	M_y	M_z
Outlet (6 in.)	Sustained loads	–27	–2,071	–69	–87	–4	–59
	Operating loads	1,103	–8,095	4,574	1,322	221	2,285
	Occasional loads	1,600	–10,800	5,100	2,600	600	3,500

External loads. Originally, the standard piping loads that are applicable for vessels were provided (TABLE 1) to the electric heater supplier as the imposed external loads on the heater nozzles. Since this electric heater is not a standard pressure vessel, is small in size and designed for very high temperature, the heater shell, nozzle and shell-to-nozzle junction failed to withstand these standard piping loads. Piping stress engineers considered heater shell and nozzle flexibilities in their stress analysis and proposed reduced loads, as indicated in TABLE 2.

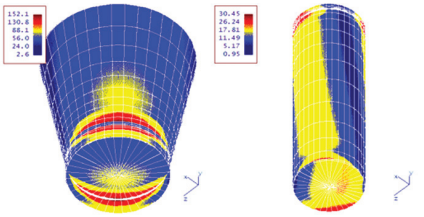

FIG. 6. Load Case 1 (Occasional): Fatigue stresses at the inlet and outlet for SCH 40S.

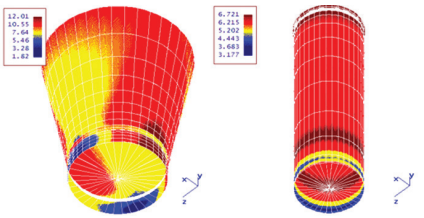

FIG. 7. Load Case 1 (Sustained): Primary membrane stresses at the inlet and outlet for SCH 80S.

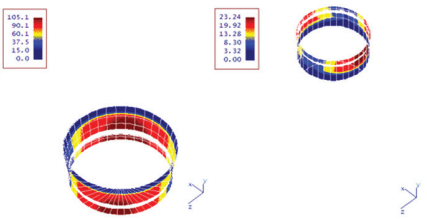

FIG. 8. Load Case 1 (Thermal): Primary membrane stresses at the inlet and outlet for SCH 80S.

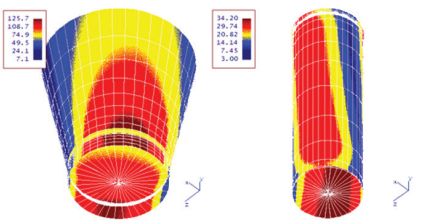

FIG. 9. Load Case 1 (Occasional): Primary membrane stresses at the inlet and outlet for SCH 80S.

Load cases. The following two load cases with various combinations of external loads were considered. While Load Case 1 considered thermal loads at design temperatures, Load Case 2 considered thermal loads at operating temperatures (i.e., inlet temperature for the inlet nozzle and outlet temperature for the outlet nozzle).

Load Case 1: At design temperature conditions:

- Sustained loads (Sustained): Dead weight (loads from component weights, fluid and internal pressure)
- Operating loads (Thermal): Sustained loads + thermal load (design)
- Occasional loads (Occasional): Sustained loads + thermal load (design) + wind load.

Load Case 2: At operating temperature conditions:

- Sustained loads (Sustained): Dead weight (loads from component weights, fluid and internal pressure)
- Operating loads (Thermal): Sustained loads + thermal load (operating)
- Occasional loads (Occasional): Sustained loads + thermal load (operating) + wind load.

Since dead weight (design)—which by definition will include the design pressure of the fluid—cannot be considered as a sustained load, dead load (design) is not considered here. As the electric heater is located on an open structure at an elevation, the wind load is considered as part of the occassional load. These load combinations are presented in **TABLE 3.**

Allowable stresses. The following allowable stresses were considered as per Part 5 of ASME Sec VIII Div 2 in the stress analysis:

- S = Allowable at design/operating temperature obtained from ASME Section II Part D[2] [3]
- $S_{PL} = 1.5S$[3] [4]
- $S_{PS} = 3Savg$[3] [4]
- Sa = Allowable obtained from a fatigue curve for the specified number of operating cycles.[3] [4]

STRESS ANALYSIS

Stress analysis was performed at the shell-to-nozzle junctions at the inlet and outlet (referred to as shell here) and the inlet and outlet nozzles, using a proprietary finite element analysis (FEA) program[a] and considering two different pipe thicknesses of the shell and nozzle, namely 40S and 80S for Load Case 1 and the thickness of 40S for Load Case 2. The results are presented in **TABLES 4–12** and **FIGS. 2–14.**

Results and discussions. Load Case 1 for the SCH 40S thick shell: An FEA using the software[a] was carried out, considering an allowable stress at a design temperature of 690°C for both the shell and inlet and outlet nozzles.

- The primary membrane stresses for Sustained loads are tabulated in **TABLE 4.** The calculated stresses are within the allowable limit.
- The primary membrane stresses for Thermal loads are tabulated in **TABLE 5.**
  - The primary membrane stresses at the inlet shell and inlet nozzle are ~357% and ~359% of allowable limits, respectively.

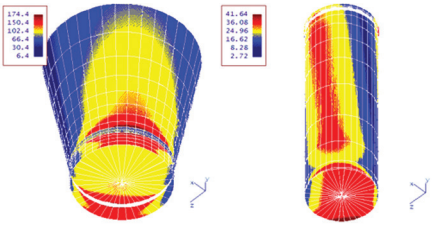

FIG. 10. Load Case 1 (Occasional): Primary + secondary + bend stresses at the inlet and outlet for SCH 80S.

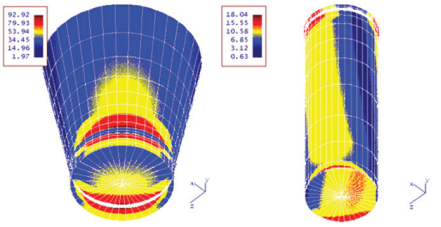

FIG. 11. Load Case 1 (Occasional): Fatigue stresses at the inlet and outlet for SCH 80S.

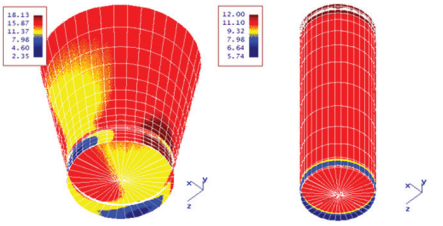

FIG. 12. Load Case 2 (Sustained): Primary membrane stresses at the inlet and outlet for SCH 40S.

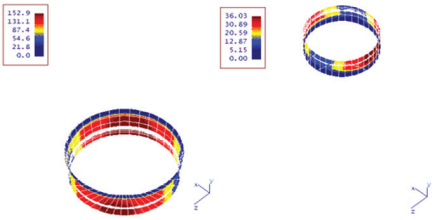

FIG. 13. Load Case 2 (Thermal): Primary membrane stresses at the inlet and outlet for SCH 40S.

TABLE 4. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (Sustained loads)

		Primary local membrane stress			
Nozzle ends	**Components**	**P_L (MPa)**	**S_{PL} (MPa)**	**Ratio, %**	**P_L (MPa)**
Inlet	Shell (6 in.)	17	Inlet	Shell (6 in.)	17
	Conical nozzle (6 in./3 in.)	18	44	Conical nozzle (6 in./ 3 in.)	18
Outlet	Shell (6 in.)	11	Outlet	Shell (6 in.)	11
	Nozzle (6 ft)	11	44	Nozzle (6 ft)	11

TABLE 5. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (Thermal loads)

		Primary local membrane stress			
Nozzle ends	**Components**	**P_L (MPa)**	**S_{PL} (MPa)**	**Ratio, %**	**Remarks**
Inlet	Shell (6 in.)	157	44	357	Overstressed
	Conical nozzle (6 in./3 in.)	158	44	359	Overstressed
Outlet	Shell (6 in.)	39	44	87	Under limit
	Nozzle (6 ft)	38	44	86	Under limit

- The primary membrane stresses at the outlet shell and outlet nozzle are within allowable limits.
- The primary membrane stresses, secondary membrane and bending stresses, and fatigue stresses for the Occasional load are tabulated in TABLE 6.
  - The primary membrane stresses at the inlet shell and inlet nozzle are ~427% and ~432% of allowable limits, respectively.
  - The primary membrane stresses at the outlet shell and outlet nozzle are ~129% of allowable limits.
  - The secondary membrane and bending stresses at the inlet shell and inlet nozzle are ~113% and ~114% of allowable limits, respectively.
  - The secondary membrane and bending stresses at the outlet shell and outlet nozzle are within allowable limits.
  - The fatigue stresses at the inlet and outlet shells and inlet and outlet nozzles are within allowable limits.

Due to the failure of the shell and nozzles as noted above for the Thermal and Occasional load conditions, it was decid-

TABLE 6. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (Occasional loads)

		Primary local membrane stress				Primary + secondary + bending				Peak fatigue stress			
Nozzle ends	Components	P_L (MPa)	S_{PL} (MPa)	Ratio, %	Remarks	$P_L + P_b + Q$ (MPa)	S_{PS} (MPa)	Ratio, %	Remarks	$P_L + P_b + Q + F$ (MPa)	S_a (MPa)	Ratio, %	Remarks
Inlet	Shell (6 in.)	188	44	427	Overstressed	284	251	113	Overstressed	151	971	15	Under limit
	Conical nozzle (6 in./3 in.)	190	44	432	Overstressed	286	251	114	Overstressed	152	971	16	Under limit
Outlet	Shell (6 in.)	57	44	129	Overstressed	66	251	26	Under limit	30	971	3	Under limit
	Nozzle (6 ft)	57	44	129	Overstressed	66	251	26	Under limit	30	971	3	Under limit

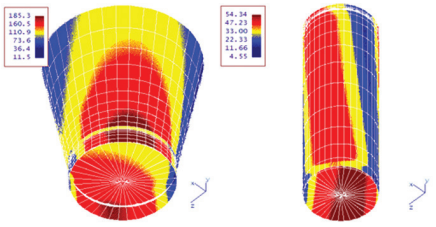

FIG. 14. Load Case 2 (Occasional): Primary membrane stresses at the inlet and outlet for SCH 40S.

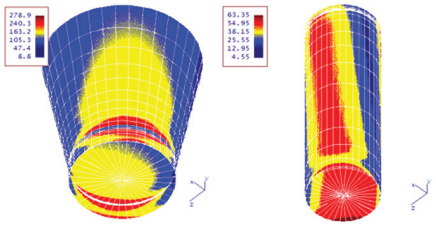

FIG. 15. Load Case 2 (Occasional): Primary + secondary + bend stresses at the inlet and outlet for SCH 40S.

TABLE 7. SCH 80S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (sustained loads)

		Primary local membrane stress			
Nozzle ends	Components	P_L (MPa)	S_{PL} (MPa)	Ratio, %	Remarks
Inlet	Shell (6 in.)	11	44	25	Under limit
	Conical nozzle (6 in./3 in.)	12	44	27	Under limit
Outlet	Shell (6 in.)	7	44	16	Under limit
	Nozzle (6 ft)	7	44	16	Under limit

TABLE 8. SCH 80S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (Thermal loads)

		Primary local membrane stress			
Nozzle ends	Components	P_L (MPa)	S_{PL} (MPa)	Ratio, %	Remarks
Inlet	Shell (6 in.)	103	44	234	Overstressed
	Conical nozzle (6 in./3 in.)	105	44	239	Overstressed
Outlet	Shell (6 in.)	23	44	52	Under limit
	Nozzle (6 ft)	23	44	52	Under limit

TABLE 9. SCH 80S thick shell: Calculated stress and limits of equivalent stress for Load Case 1 (Occasional loads)

		Primary local membrane stress				Primary + secondary + bending				Peak fatigue stress			
Nozzle ends	Components	P_L (MPa)	S_{PL} (MPa)	Ratio, %	Remarks	$P_L + P_b + Q$ (MPa)	S_{PS} (MPa)	Ratio, %	Remarks	$P_L + P_b + Q + F$ (MPa)	S_a (MPa)	Ratio, %	Remarks
Inlet	Shell (6 in.)	124	44	282	Overstressed	172	251	68	Under limit	92	971	9	Under limit
	Conical Nozzle (6 in./3 in.)	126	44	286	Overstressed	174	251	69	Under limit	93	971	9	Under limit
Outlet	Shell (6 in.)	34	44	77	Under limit	39	251	15	Under limit	18	971	2	Under limit
	Nozzle (6 ft)	34	44	77	Under limit	38	251	15	Under limit	18	971	2	Under limit

ed to repeat the analysis for higher shell thickness (SCH 80S) to check whether the increase in thickness coulc bring the induced stresses within allowable limits.

For Load Case 1 for the SCH 80S thick shell: The stress analysis was carried out considering allowable stresses at a design temperature of 690°C for both the shell and inlet and outlet nozzles.

- The primary membrane stresses for Sustained loads are tabulated in TABLE 7, and the calculated stresses are within the allowable limit.
- The primary membrane stresses for Thermal loads are tabulated in TABLE 8.
  - The primary membrane stresses at inlet the shell and inlet nozzle are ~234% and ~239% of allowable limits, respectievly.
  - The primary membrane stresses at the outlet shell and outlet nozzle are within allowable limits.
- The primary membrane stresses, secondary membrane and bending stresses, and fatigue stresses for Occasional load are tabulated in TABLE 9.
  - The primary membrane stresses at the inlet shell and inlet nozzle are ~282% and ~286% of allowable limits, respectively.
  - The primary membrane stresses at the outlet shell and outlet nozzle are within allowable limits.
  - The secondary membrane and bending stresses at the inlet and outlet shells and nozzles are within allowable limits.
  - The fatigue stresses at the inlet and outlet shells and inlet and outlet nozzles are within allowable limits.

The shell and nozzle failed with the SCH 80S thickness, as well. Any further increase in shell thickness to bring the induced stress within allowable limits could not be considred since the heater supplier informed that any increase in pipe schedule above 80S will result in the shell's inside diameter becoming smaller than the bundle diameter.

For Load Case 2 for the SCH 40S thick shell: The stress analysis was carried out considering the allowable stress at an operating temperature of 130°C at the inlet and 649°C at the outlet for both shell and nozzles.

- The primary membrane stresses for Sustained loads are tabulated in TABLE 10. The calculated stresses are within the allowable limits.
- The primary membrane stresses for Thermal loads are tabulated in TABLE 11. The calculated stresses at the inlet and outlet shells, and the inlet and outlet nozzles are within the allowable limits.

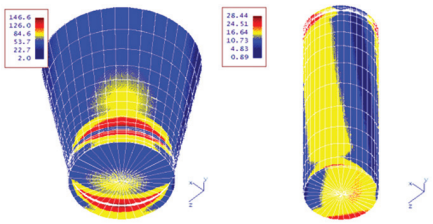

FIG. 16. Load Case 2 (Occasional): Fatigue stresses at the inlet and outlet for SCH 40S.

- The primary membrane, primary + secondary + bending stresses and fatigue stresses for Occasional loads are tabulated in **TABLE 12.** The calculated stresses at the inlet and outlet shells, and the inlet and outlet nozzles are within the allowable limits.

Since the induced stresses in the shell and inlet and outlet nozzles are wthin allowable limits for all the three load combinations (i.e., Sustained, Thermal and Occasional), a further increase in thickness from 40S to 80S is not required.

Load Case 1, where the Thermal load is considered at design temperature, results in stresses exceeding the allowable limits with thickness higher than the standard thickness (40S) of pipe shell. An increase in shell thickness of more than 80S is infeasible since that results in the inner diameter of the shell becoming smaller than the outside diameter of the heater bundle, thereby making the insertion of the heater bundle inside the shell impossible.

Load Case 2, where the Thermal load is considered at operating temperature, is a more practical scenario compared to Load Case 1 since the heater nozzles and shell will be under operating conditions most of the time—this is particularly true in combination with the wind load, which by definition is considered an Occasional load. This load combination also enabled the adoption of a standard pipe wall thickness by keeping the induced stresses within the allowable limits.

Takeaways and recommendations.

With cost-competitive and schedule-driven projects, detailed engineering contractors (DECs) are expected to specify all technical requirements correctly and completely in the requisition document to avoid changes at a later stage that may affect the project cost and schedule. To avoid post-order changes, DECs should not over-specify the external loads (e.g., specifying standard piping loads for vessels and exchangers for electric heaters). Instead, DECs should evaluate various external loading combinations and specify the most feasible load combination.

As explained above, a simulation study with appropriate load combinations, considering operating temperatures instead of design temperatures, can help avoid increased hardware costs, and (in this case) increase the thickness of the electric heater shell during the project's detailed design stage, preventing both cost and schedule overruns.

To avoid late changes in the supplier design with a conservative load combination, it is recommended to consider thermal loads at operating conditions—the more likely scenario—rather than at design conditions, which tend to be conservative and may result in a late change in form and an increase in the thickness of the shell and/or nozzles. HP

TABLE 10. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 2 (Sustained loads)

		Primary local membrane stress			
Nozzle ends	**Components**	**P_L (MPa)**	**S_{PL} (MPa)**	**Ratio, %**	**Remarks**
Inlet	Shell (6 in.)	17	200	8	Under limit
	Conical nozzle (6 in./3 in.)	18	200	9	Under limit
Outlet	Shell (6 in.)	11	63	17	Under limit
	Nozzle (6 ft)	11	63	17	Under limit

TABLE 11. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 2 (Thermal loads)

		Primary local membrane stress			
Nozzle ends	**Components**	**P_L (MPa)**	**S_{PL} (MPa)**	**Ratio, %**	**Remarks**
Inlet	Shell (6 in.)	151	200	75	Under limit
	Conical nozzle (6 in./3 in.)	153	200	76	Under limit
Outlet	Shell (6 in.)	36	63	57	Under limit
	Nozzle (6 ft)	36	63	57	Under limit

NOTE

[a] Paulin Research Group, Codeware Nozzle PRO v15.0 Build 16

NOMENCLATURE

P_L = Primary local membrane stress
P_b = Primary bending stress
Q = Secondary membrane + bending stress
F = Peak fatigue stress
S = Allowable stress at design/operating temperature
S_{PL} = Allowable primary local membrane stress
S_{PS} = Allowable primary + secondary membrane and bending stress
S_a = Allowable peak fatigue stress
S_{avg} = Average allowable stress between design/operating temperature and ambient temperature

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TABLE 12. SCH 40S thick shell: Calculated stress and limits of equivalent stress for Load Case 2 (Occasional loads)

		Primary local membrane stress				Primary + secondary + bending				Peak fatigue stress			
Nozzle ends	**Components**	**P_L (MPa)**	**S_{PL} (MPa)**	**Ratio, %**	**Remarks**	**$P_L + P_b + Q$ (MPa)**	**S_{PS} (MPa)**	**Ratio, %**	**Remarks**	**$P_L + P_b + Q + F$ (MPa)**	**S_a (MPa)**	**Ratio, %**	**Remarks**
Inlet	Shell (6 in.)	184	200	92	Under limit	277	407	68	Under limit	145	971	15	Under limit
	Conical nozzle (6 in./3 in.)	185	200	92	Under limit	279	407	69	Under limit	147	971	15	Under limit
Outlet	Shell (6 in.)	54	63	86	Under limit	63	270	23	Under limit	28	971	3	Under limit
	Nozzle (6 ft)	54	63	86	Under limit	63	270	23	Under limit	28	971	3	Under limit

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Why sulfur plants fail: An in-depth study of sulfur recovery unit failures—Part 2

Equipment malfunction or an unplanned shutdown of a sulfur recovery unit (SRU) can have a significant effect on a production company's profitability, along with an equally serious impact on personnel safety and the environment. The goal of this article is to establish the highest-probability threats to the reliability of sulfur recovery facilities and to focus industry attention on this issue. This article is a continuation of Part 1, which was featured in the October issue of *Hydrocarbon Processing*.

Thermal excursions. Thermal excursion (FIG. 4) is a general term that encompasses both sulfur fires and unacceptably high process temperatures. Thermal excursions in the sulfur recovery industry typically fall into the following five categories:

- **Auto-ignition of sulfur vapor/liquid [auto-ignition temperature of 232°C (450°F)]:**
  - Auto-ignition of sulfur vapor is common when air is purposefully or accidentally introduced into a hot SRU during a trip or a restart.
  - Some catalyst beds and condenser inlets contain sulfur vapor or liquid at or above the auto-ignition temperature.
- **Pyrophoric ignition of sulfur at any temperature:**
  - Iron sulfide (FeS) produced from wet sulfur contact corrosion is pyrophoric.
  - Exposure of the pyrophoric material provides the ignition source to ignite sulfur at any temperature.
  - Pyrophoric ignition is relatively common in sulfur storage vessels.
  - It can occur anywhere in the SRU where sulfur has been allowed to freeze on metal surfaces.
- **Self-heating tail gas unit (TGU) catalyst [at temperatures over 93°C (200°F)]:**[a]
  - The active form of TGU catalyst (cobalt and molybdenum sulfides) is self-heating/pyrophoric and will auto-ignite in the presence of oxygen.
- **Overheating of burner chambers on fuel gas firing [refractory damage possible above 1,537°C (2,800°F)]:**
  - Stoichiometric natural gas firings during shutdowns, startups and standbys generate a flame temperature of 1,982°C (3,600°F).
  - Overheating of burner chambers can damage refractory unless sufficient cooling gas is added.
- **Overheating of burner chambers on acid gas firing [refractory damage above 1,537°C (2,800°F)]:**
  - Pure H_2S at one-third burn stoichiometry generates a peak flame temperature of 1,454°C (2,650°F); this does not result in damage.
  - Temperatures can be increased by oxygen enrichment, hydrocarbon addition, acid gas bypass operation and stoichiometries greater than one-third, among others. Worst-case temperatures are over 4,704°C (8,500°F) (100% combustion of H_2S with pure oxygen).

Thermal excursions can result in rapid catalyst damage at temperatures of more than 500°C (932°F). Even more significantly, thermal excursions can result in the softening of carbon steel at temperatures over 380°C (716°F) and in the complete melting of carbon steel at temperatures over 1,425°C (2,597°F). The melting of carbon steel will result in the additional failure route of an immediate process fluid release.

FIG. 4. Examples of SRU thermal excursion.

The author's company's case studies include hundreds of thermal excursion incident investigations. The auto-ignition of sulfur, the pyrophoric ignition of sulfur, and the overheating of burner chambers while burning fuel gas all occur relatively frequently and in roughly equal proportions (around 5–6 cases/yr each), indicating that the SRU industry still suffers from numerous design and procedural flaws. Thermal excursions due to oxygen contacting active TGU catalyst are less common (around one case/yr), likely due to a combination of increased awareness around this issue (i.e., catalyst vendors are good at informing of the self-heating nature of this catalyst), as well as the more limited ability for air to enter this part of the SRU. The final category of thermal excursions from acid gas firing is the least common; it is usually associated with problems occurring during oxygen enrichment. The author's company has only encountered

a few of these cases, likely because the potential dangers of oxygen enrichment are relatively well known and safeguarding procedures are well implemented.

Incident investigations for thermal excursions in vessels outside of burner chambers are aided by the relative prevalence of accurate thermocouples in these areas. Once the starting location of the thermal excursion is determined, then the operating history can be reviewed to determine which of the potential causes (auto-ignition, pyrophoric FeS ignition or TGU catalyst self-heating) was most likely the cause.

Incident investigations within burner chambers (reaction furnace, fired heaters and incinerators) can be made more difficult by the fact that temperature measurement devices in these areas are more likely to be inaccurate or nonexistent, and that peak flame temperatures are often much greater than the average or local temperatures measured by the devices that do exist. In these cases, good simulations of flame temperatures based on metered or assumed flowrates are an important part of the investigation.

Regarding prevention of thermal excursions, the following recommendations are associated with the most common root causes:

- **Auto-ignition of sulfur vapor/liquid:**
  - Ensure that the process design does not permit air ingress into the SRU when the plant is hot and contains sulfur. The most common ways that this unwanted air ingress occurs is when reaction furnace nozzle purges are done with air (air purges should be automatically switched to nitrogen during a trip) or when purges of burner management systems (BMSs) use air as the purge medium (again, nitrogen or some other inert gas should be used as the burner purge medium when the plant is hot and full of sulfur).
  - Be aware of the auto-ignition characteristics of sulfur and understand that operating procedures prevent manual introduction of air when the plant is hot and full of sulfur.
  - Use portable oxygen analyzers whenever sulfur plants are switched from acid gas firing to fuel gas firing (i.e., for hot standbys and shutdowns) to confirm proper stoichiometry. Even very brief periods of excess stoichiometry at this point can result in significant thermal excursions.
  - Set alarm points on all process thermocouples that would be consistent with a sulfur fire.
  - Ensure that proper fire response procedures are in place; eliminate the excess air first and then use a suitable fire suppression medium.
- **Pyrophoric ignition of sulfur at any temperature:**
  - Ensure that plant personnel are aware of the properties of pyrophoric FeS, and that fires can occur at any temperature when excess air is first introduced to the sulfur plant. One of the most common causes of fire is during the startup process, when frozen sulfur, left during a turnaround, melts and exposes the underlying pyrophoric material.
  - Procedures for the introduction of excess air during shutdowns/turnarounds should involve very gradual increases in excess oxygen levels, and should allow for careful monitoring and rapid removal of the air if a fire is discovered.
  - Ensure proper insulation and/or heating of appropriate sulfur plant areas to minimize the risk of pyrophoric FeS formation.
  - Ensure that the sulfur plant design and construction eliminate low points where liquid sulfur can collect in process piping and vessels. These unexpected sulfur pools are the primary locations for pyrophoric sulfur fires.
- **Self-heating TGU catalyst:**
  - Plant personnel should be aware of the self-heating nature of this catalyst and ensure that design and operating procedures minimize the risk of air introduction to hot and activated TGU catalyst.
  - To confirm proper stoichiometry, portable oxygen analyzers should be used whenever TGU burners are first restarted on fuel gas. Even very brief periods of excess stoichiometry can result in significant thermal excursions.
  - TGU catalyst should either be passivated during shutdown (involving the gradual introduction of increasing excess oxygen levels) or kept under an inert gas blanket during turnaround and catalyst loading/unloading.
- **Overheating of burner chambers on fuel gas firing [refractory damage above 1,538°C (2,800°F)]:**
  - Stoichiometric natural gas firing should always include a sufficient volume of cooling gas, such as nitrogen or dry steam. A 4:1 volume ratio of inert cooling medium to fuel gas is usually sufficient to result in acceptable peak flame temperatures.
  - Burner chamber design should include the most accurate modern combination of thermocouples and pyrometers for measuring process gas temperatures and refractory temperatures. Regardless of the accuracy of the temperature measurement, the addition of a cooling medium is still required during stoichiometric firing—otherwise, peak flame temperatures will exceed the refractory melting temperature, regardless of the reported temperature.
  - For burner chambers with multiple temperature zones, a temperature measurement (or other suitable safeguards) should exist for each zone.
- **Overheating of burner chambers on acid gas firing [refractory damage above 1,538°C (2,800°F)]:**
  - Redundant safeguards should be employed whenever oxygen enrichment is used (e.g., temperature alarms and trips, oxygen limits, and simulated temperatures).
  - Additional safeguards should be used whenever multiple temperature-increasing operational modes are used (e.g., oxygen plus split flow, or split flow plus fuel gas co-firing).

Process fluid release. Process fluid releases of concern from an SRU typically fall into the following three categories:

1. **H_2S gas [National Institute for Occupational Safety and Health "immediately dangerous to life or health" (NIOSH IDLH) value of 300 ppmv]:**
   - Present in high concentrations everywhere in the sulfur plant
   - Also contained in produced liquid sulfur and released at all stages of the liquid sulfur collection, storage and transportation
2. **Sulfur dioxide (SO_2) gas (NIOSH IDLH of 100 ppmv):**
   - Present in approximately a 2:1 H_2S:SO_2 ratio in all streams between the reaction furnace and the TGU reactor
   - All sulfur species present in the sulfur plant tail gases are normally oxidized to SO_2 prior to release to atmosphere; it can be very high during upsets
   - Can be present in nearly pure SO_2 form in some tail gas technologies
   - Generated in large concentrations during sulfur fires
3. **Liquid sulfur [typically more than 150°C (302°F) and can cause severe burns when in contact with skin]:**
   - Present in all SRU condensers and other low-temperature areas
   - Removed from the condensers through a combination of sealing devices and rundown lines
   - Stored onsite in sulfur pits and storage tanks
   - Often transported from site in trucks, rail cars, barges or liquid-sulfur pipelines
   - Can ignite, causing even greater temperatures and increased risk of contact.

The presence and typical concentrations of H_2S, SO_2 and liquid sulfur within the SRU are presented in FIG. 5. As shown, virtually everywhere in the SRU, the process concentrations of H_2S and SO_2 are above the air concentration values that are considered immediately dangerous to life or health. In most cases, the only allowable/purposeful release of process fluid to the environment is from the back end of the TGU—released either directly to atmosphere or via an incinerator/thermal oxidizer. Even with these low concentrations, the release is usually done at elevation and at high temperatures to minimize safety risks. Process upsets can still increase the concentrations to levels that are dangerous to nearby personnel.

Releases of unacceptable levels of H_2S, SO_2 or liquid sulfur can, and do, occur in many ways. In the least concerning cases, these emissions may only be an odor or a visual pollution problem. However, in the worst cases, these emissions can cause serious safety concerns, such as shelter-in-place requirements for the plant or surrounding neighborhoods, injuries, hospitalizations or deaths. Some of the ways that these unwanted releases can occur include the following:

- Process gas escaping through process lines (e.g., backflow of raw acid gas through process air lines)
- Highly increased stack emissions during serious upsets: SO_2 levels at 5% to more than 10%, and uncombusted H_2S between 1% and 5%
- Personnel exposure to process fluids during routine sulfur rundown inspections:
  - Most plant designs from 1950–2000 included open-air look boxes to confirm liquid sulfur flow from condensers.
  - Operators are often not properly aware of H_2S and SO_2 concentrations in these look boxes.
  - Seal legs upstream of these look boxes can be over-pressured and can release process gases, as well.

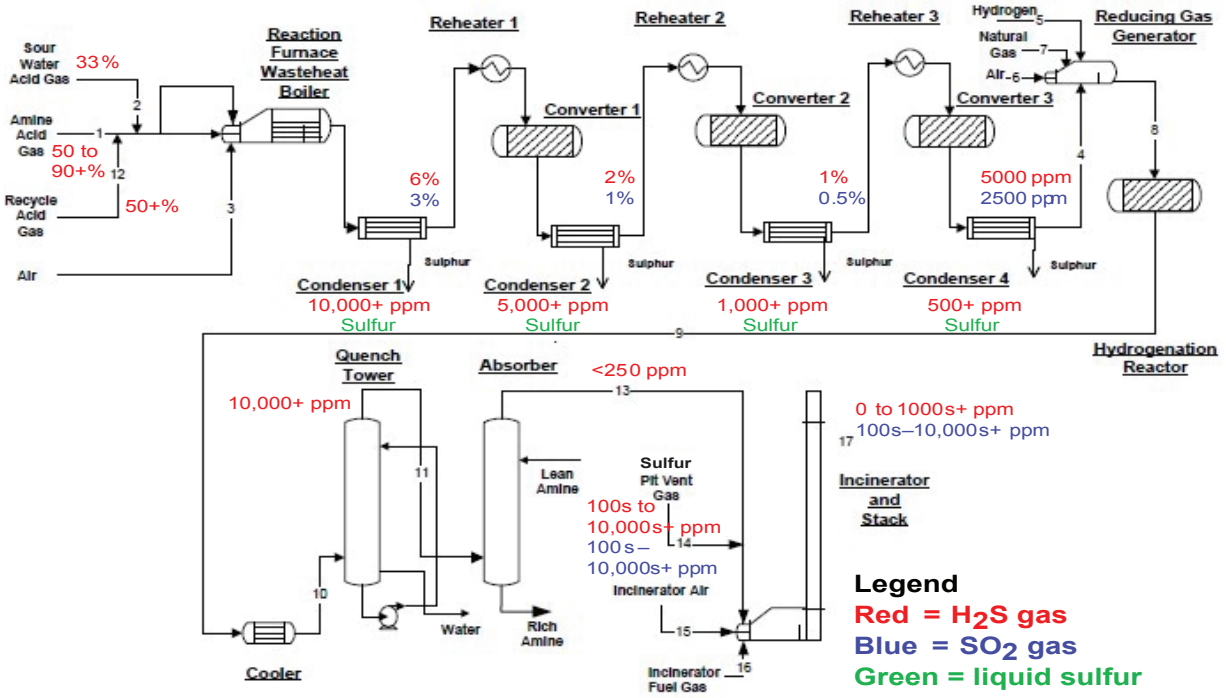

FIG. 5. Process fluid concentrations in the SRU.

- Intentional or unintentional process emissions to atmosphere from liquid sulfur storage areas (e.g., pit, tank, loading)
  - Emissions from storage areas are often allowed to vent directly to atmosphere.
  - Even if emissions are collected for processing, these systems are often unreliable.
  - Emission points are sometimes near or at ground level.
  - Operators and transportation personnel are often not fully aware of the potential of H_2S and SO_2 concentrations.
- Loss of containment due to fires, explosions, corrosion or plugging: Equipment damage or plugging can result in the secondary impact of unwanted process fluid release.
- Manual opening of process lines to atmosphere: Many incidents are due to improper safety procedures when opening sample points or process bleeds.
- Equipment entry during a turnaround: H_2S, SO_2 and sulfur are often present in the equipment.

Examples of process fluid releases are shown in FIG. 6.

A review of the author's company's case files reveals around 30 incidents of serious process fluid releases over the past 30 yr, or roughly one serious process fluid release incident every year. These cases include:

- Six gas release incidents involving H_2S deaths or knockdowns
- Six other high-concentration H_2S releases not involving deaths or knockdowns
- Ten shelter-in-place incidents (large SO_2 or H_2S releases)
- Four liquid sulfur injuries or deaths
- Five significant liquid sulfur spills.

Despite the constant improvements in design, operation and understanding of SRUs, physical and mechanical failures continue to occur frequently, causing loss of processing and profits, and leading to significant safety incidents.

FIG. 6. Examples of process fluid releases.

FIG. 7. Examples of SRU explosions.

Because of the relative scarcity of H_2S and liquid-sulfur-related deaths and injuries in the author's company's files, a review of online records from the Occupational Safety and Health Association (OSHA) for these two categories was undertaken to better understand the frequency of these events. While this review only shows U.S. incidents, and only for the period of OSHA records (starting in 1984), it still provides a good appreciation of the prevalence of these types of cases. This data is detailed below:

- **OSHA-recorded H_2S deaths in the U.S. (all industries)**[7]
  - 1984–1989: 42 deaths (7/yr)
  - 1990–1999: 70 deaths (7/yr)
  - 2000–2009: 48 deaths (4.8/yr)
  - 2010–2021: 43 deaths (3.6/yr)
  - Total U.S. H_2S deaths in amine, sour water stripping, SRU operations: Eight deaths
  - Total U.S. H_2S deaths in liquid sulfur transportation: Eight deaths
  - Total U.S. liquid sulfur injuries or deaths: Six cases involving nine injuries and one death.

The 16 SRU-related H_2S deaths equate to around one H_2S-related death every 2 yr in the sulfur industry, while the liquid sulfur cases equate to around one injury or death every 3 yr. Overall, although process-fluid-related incidents remain relatively rare in the SRU industry, they are still occurring and do have significant consequences. This data shows that the industry still requires improvements in design and procedures to avoid these types of process-fluid-release failures.

Regarding incident investigations for process fluid releases, the type of release (H_2S, SO_2 or liquid sulfur) is usually obvious. The determination of the root cause(s) usually comes down to a combination of design reviews, equipment walkthroughs, historical data reviews and personnel interviews to determine if the release was the fault of design or due to operational or personnel procedures.

Regarding prevention of future process fluid releases, the presence of IDLH levels of H_2S and SO_2 within the normal process gas flow path is well known in the industry. For this reason, proper design, safeguarding and instrumentation of SRUs are commonplace, and regular detailed hazard and operability studies (HAZOPs) are recommended to ensure that the design meets current standards; a full discussion of recommended safeguarding is outside the scope of this article. However, most process gas or fluid injuries and deaths in the author's company's investigations and in OSHA records are not related to mechanical failures, but, instead, to poor understanding by plant personnel of the potential concentrations of dangerous process fluids at all locations—and also to improper procedures involved with inspecting, handling and opening various process locations, especially in the liquid sulfur collection, storage and transportation areas, as evidenced by the high number of H_2S deaths in the transportation sector. Improved training for personnel involved in these areas, along with more consistent design and procedural safeguards, would go a long way toward reducing the risk of serious process-fluid-release incidents.

Explosions. Explosions in the sulfur recovery industry (FIG. 7) typically fall into four categories:

1. **H_2S explosions—H_2S lower explosive limit (LEL) 3.2%, the lowest possible LEL over the full range of normal SRU temperatures:** Most likely in liquid sulfur storage and transportation vessels due to H_2S release from liquid sulfur[8]
2. **Sulfur dust explosions (sulfur dust LEL is 35 mg/l):** Most likely in solid sulfur forming, storage and transportation vessels

due to friability of solid sulfur—and also possible in the cleanup of sulfur spills

3. **Explosions associated with fuel gas burner ignition (methane LEL 5%):** Most likely with improper or missing BMSs when lighting SRU reaction furnaces, reheaters and incinerators
4. **Explosions (deflagrations) associated with rapid vaporization of liquids (most SRU vessels are rated for 15 psi–50 psi (100 kPa–350 kPa):** Most likely with high-pressure waste heat boiler leaks or with rapid flashing of a heat transfer medium.

The author's company's direct experience with SRU explosions includes the following:

- Sulfur storage (pits/tanks) H_2S explosions: Six cases
- Sulfur transportation H_2S explosions: One case
- Sulfur dust explosions: Two cases
- Burner ignition explosions: Three cases
- Liquid-to-vapor pressure explosions: Three cases
- Unknown internal explosions: Two cases.

In addition, the OSHA records review indicated one SRU explosion with which the author's company was not familiar. A refinery SRU explosion resulted in four people being hospitalized, although further details about the cause of the explosion were not provided.

Overall, these cases represent an SRU explosion incident rate of around one incident every 2 yr. The author's company is not aware of any deaths associated with any of these explosions; however, most of the cases have involved near misses (i.e., personnel were in the vicinity), and some have involved injuries and hospitalizations. All cases have involved significant equipment damage and/or significant lost processing opportunities.

Regarding incident investigations for SRU explosions, the first step usually involves a review to determine the most likely type of explosion (H_2S, sulfur dust, fuel gas, pressure). Although, in some cases, this may be obvious, other cases may require a more detailed investigation. As with process fluid release incidents, the determination of an explosion's root cause usually comes down to a combination of design reviews, equipment walkthroughs, historical data reviews and personnel interviews to determine if the release was the fault of design or due to operational or personnel procedures.

Regarding the prevention of future explosions, the following recommendations are based on the most common root causes of explosions:

- **H_2S explosions:**
  - Ensure proper sweep gas design for liquid sulfur storage and transportation vessels so that the LEL cannot be reached. In addition, confirm accurate measurement of the sweep flowrate so that operators know when the sweep system is having problems. Backup options for non-working sweep systems (e.g., second eductor, natural venting, nitrogen blanketing) should also be considered.
  - Strongly consider degassing of liquid sulfur to remove enough H_2S to prevent reaching LEL downstream of the degassing system.
  - Include designed and operated grounding systems in sulfur storage, transfer, loading and transportation systems, and check that proper grounding is in place before liquid sulfur loading commences.
- **Sulfur dust explosions:**
  - Properly educate personnel on the possibility of dust explosions.
  - Employ suitable dust collection and/or suppression systems during operation of a process that might create sulfur dust.
- **Explosions associated with burner ignition:**
  - Confirm that up-to-date BMSs are in place.
  - Where modern BMSs are not in place, review procedures to prevent reaching fuel gas LEL during burner ignition.
- **Explosions associated with rapid vaporization of liquids:**
  - Employ detailed design and operating HAZOP reviews to minimize the chances of expansive fluids entering hot process vessels.
  - Review all available pressure relief options to prevent deflagration in case of rapid vaporization.

Takeaways. Despite the constant improvements in design, operation and understanding of SRUs, physical and mechanical failures continue to occur frequently, causing loss of processing and profits, and leading to significant safety incidents. Based on the author's company's case files, the serious incident rates for the five failure types discussed in this article include:

- Corrosion: 25–30 cases/yr
- Plugging: 25–30 cases/yr
- Thermal excursions: More than 20 cases/yr
- Process fluid releases: One serious incident per year, one SRU-related H_2S death every 2 yr in OSHA files, and one liquid sulfur-related death or injury every 3 yr in OSHA files
- Explosions: One serious incident every 2 yr.

It is hoped that this summary will serve to focus the industry's attention on the continued high prevalence of these types of dangerous incidents in the SRU industry, along with the available means for prevention, and the need for even more improvements in SRU design, operation and personnel training. HP

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NOTES

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[a] Laboratory test data was provided by Porocel.

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